Rulemaking: 06-02-013
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Date: December 11, 2006
Witnesses: Various

PACIFIC GAS AND ELECTRIC COMPANY

2006 LONG-TERM PROCUREMENT PLAN

ORDER INSTITUTING RULEMAKING TO INTEGRATE PROCUREMENT POLICIES AND CONSIDER LONG-TERM PROCUREMENT PLANS

VOLUME 2

PUBLIC VERSION
REDACTED

PACIFIC GAS AND ELECTRIC COMPANY
VOLUME 2 – 2006 LONG-TERM PROCUREMENT PLAN

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I. INTRODUCTION

A. Introduction

Volume 2 of Pacific Gas and Electric Company's ("PG&E") 2006 LTPP addresses various policy issues raised in the Scoping Memo and proposes steps the California Public Utilities Commission ("Commission") should take to address these issues. In Section I, PG&E addresses the impact of Resource Adequacy ("RA") requirements on PG&E's procurement costs and describes uncertainties arising from the RA counting rules. PG&E also addresses the impact on procurement of Greenhouse Gas ("GHG") performance standards, the California Independent System Operator's ("CAISO") proposed Market Redesign and Technology Upgrade ("MRTU"), California Department of Water Resources ("DWR") contract expiration, and the Energy Action Plan ("EAP") goal of 33% renewables by 2020.

In Section II, PG&E describes in detail its competitive procurement practices, credit and collateral policies and its use of an Independent Evaluator in its recent 2004 Long Term Request for Offers ("LTRFO").

In Section III, PG&E describes risk management practices including hedging strategies and its use of the To-expiration-Value-at-Risk ("TeVaR") metric.

Finally, in Section IV, PG&E proposes a new Planning Reserve Margin ("PRM") to ensure continued reliable electric service in Northern California, addresses uncertainties in generation resources, supports its proposed gas supply and nuclear supply plans, offers a ratemaking proposal under Decision ("D.") 06-07-029, proposes processes for streamlining reporting requirements, and proposes ratemaking for its Emerging Renewables Resource Program ("ERRP").

Volume 2 provides the information necessary for the Commission to address many of the critical policy issues facing California regarding long-term planning and procurement. The information in this volume, and Volume 1, provides the Commission a complete picture of PG&E's planning process and a roadmap for ensuring that northern California has reliable, environmentally friendly, reasonably priced energy over the next 10 years.

B. Discussion on Recent/Upcoming Policy Issues

1. Impact of RA on Costs and Procurement

In October 2005, the Commission issued a decision establishing annual and monthly RA requirements and demonstrations for load-serving entities ("LSE").[1] In Summer 2006, the Commission issued two subsequent RA decisions, the first addressing the adoption of Local RA requirements and the second addressing implementation issues focused on System RA.[2]

It is difficult to say whether and by how much implementation of the current RA requirements may have increased cost. For example, in the absence of the year-ahead 15-17% PRM and all the related counting rules adopted by the Commission, it is likely PG&E would have procured planning reserves but wouldn't necessarily have counted resources in the same way and may not have used the same PRM. In addition, to the extent RA requirements result in more resources being available to the CAISO to meet reliability needs, then LSE costs for Reliability Must-Run ("RMR") contracts and dispatch under the Reliability Capacity Services Tariff ("RCST") mechanism should be reduced. Thus, PG&E cannot at this point determine the exact effect that the RA requirements have had on costs.

Future phases of the RA proceeding are expected to address numerous issues including a review of the current RA framework and the following potential refinements: (1) the addition of a zonal requirement; (2) implementation of performance standards on generators that may modify the capacity level available from their generation to satisfy the PRM based on performance; (3) review of current counting rules for qualifying capacity based on history of the program to date and during the July 2006 heat storm; (4) implementing a backstop procurement mechanism to be used to ensure new generation is developed timely to meet the reliability needs of the system; and (5) development a longer term RA structure which might include of a centralized capacity market.

Although the Commission has made substantial progress in establishing System and Local RA requirements, there are still a number of critical undefined elements in the RA program that create uncertainty. In Volume 1, Section IV.D,

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[1] D.05-10-042.

[2] D.06-06-064 (establishing Local RA requirements) and D.06-07-031 (addressing RA implementation issues).

PG&E described the uncertainties associated with potential changes in RA counting rules, and the effect of these potential changes on procurement. For planning purposes, PG&E assumed a reduction in RA value of 500 megawatts ("MW") for its resources. While PG&E is not in this testimony advocating changes to the RA counting rules, the following examples demonstrate the reasonableness of PG&E's assumed 500 MW RA reduction.

- If PG&E is not able to count emergency Demand Response ("DR") programs towards RA requirements,[3] PG&E would need to procure more RA capacity, plus the equivalent 15% increase in planning reserve requirements.[4] PG&E's emergency DR programs currently amount to about 300 MW, and could double over time with the recent additions proposed by PG&E.[5] Considering the increase in effective planning reserves, the total impact of not being able to count emergency programs for RA purposes would be on the order of 700 MW of increased RA procurement need (*i.e.*, 600 MW times 1.15).

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[3] The Commission's treatment for quantifying the capacity of DR programs for RA purposes has not been finalized. In D.04-10-035, at page 27 the Commission stated:

> We will allow these programs to be quantified using comparable evaluation data from similar programs, whether conducted in California or outside of California. We direct the inter-agency staff team supporting R.02-06-001, or its successor, to assist in developing and/or reviewing assessments of these programs and developing practical guidelines for these programs and tariffs. As with energy efficiency, we direct participants in R.02-06-001 or its successor to develop measurement and evaluation activities that will provide the data that are needed to permit complete evaluations of demand response programs and tariffs.

A later decision asked IOUs to quantify the impacts of existing programs for CEC review, but did not establish firm counting rules. *See* D.05-10-042. In the next phase of the RA proceeding, PG&E expects the Commission to review the counting rules and their accuracy. Since formal rules have not been adopted for DR programs, it is difficult to say what level these and future programs may ultimately be counted for RA purposes. In addition, if counting rules for new programs rely on history to demonstrate their level of reliability, there would be a time lag between when a program is implemented and when it could be used for RA capacity demonstration purposes.

[4] The CAISO has in the past taken the position that emergency-only DR should not count for RA because it increases the likelihood that PRM will not be sufficient to cover operating reserves, regulation, forced outages and load forecast deviations. *See* Opening Comments Of The CAISO On The Draft Decision Of ALJ Wetzell Regarding Opinion On Resource Adequacy Requirements, CAISO, October 17, 2005, p. 12.

[5] *See* PG&E's August 30, 2006 filing in Rulemaking ("R.") 06-02-013 in response to Commissioner Peevey's August 9, 2006 Assigned Commissioner's Rulings requesting that PG&E and the other Investor-Owned Utilities ("IOU") propose enhancements to their DR portfolios.

- If RA counting rules increase the number of days used to measure the performance of DR programs from, for example, four to six per month, the amount of qualifying capacity from DR programs will be reduced because of the need to show demand reductions for a greater number of hours.[6]

- If the RA counting rule that determines the qualifying capacity of wind generation is modified to what is typically observed on high temperature days, during the highest peak hours, qualifying capacity for wind turbines would decrease by approximately 20% of installed capacity (down to 5% of installed capacity) for the peak month.[7] For example, assuming the RA counting rules reduce wind RA value by 20% of its installed capacity, then for every 1,000 MW of new installed wind capacity, PG&E would need to procure 200 MW more of RA capacity requirements. If the rule is changed to reflect wind availability on the peak hour of PG&E's area of each month, the need would be even greater.

If the net cost of incremental RA capacity is $60/kilowatt-year ("kW-yr"),[8] a 500 MW increase in required RA procurement would result in a cost increase of about $30 million per year.

2. Impact of Greenhouse Gas Emission Performance Standard on Procurement

Senate Bill ("SB") 1368 directs the Commission to develop a GHG emission performance standard ("EPS") for baseload electricity generating resources for

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[6] The current RA counting rule for DR requires a minimal seasonal performance level of 48 hours in conjunction with the 0.89% of monthly system peak limit on two-hour demand resources. *See* D.04-10-035, Conclusion of Law 19.

[7] The adopted counting rules for intermittent resources use the 6-hour window of hours (noon to 6 p.m. on weekdays) to calculate their qualifying capacity. During some summer months, wind's output during this window can average about 30% of the wind installed capacity. On hot days, such as the July 2006 heat storm, wind was only approximately 5% of the total installed wind capacity during the system peak hour. *See* Reply Testimony Of David L. Hawkins On Behalf Of The California Independent System Operator, filed August 10, 2006, in A.06-04-012. The graph on page 8 of Mr. Hawkins' testimony illustrates the inverse correlation of wind generation with temperature. The hottest days of the storm were Saturday and Sunday, July 22 and 23. These were also the days that showed the lowest output. As temperatures dropped by July 26 and 27, wind generation increased. This performance during the heat storm may cause the RA counting rule for wind capacity to be revisited and potentially adjusted at some point in the RA proceeding.

[8] *See* Volume 1, Section III.F.3 for the RA capacity prices under the various scenarios.

Commission jurisdictional LSEs by February 1, 2007. In addition, Assembly Bill 32 ("AB 32") mandates accounting of all GHG emissions associated with electricity used in California and a statewide aggregate GHG emissions limit on electric and non-electric sectors equivalent to 1990 levels by 2020. The Commission is implementing these statutes in Phases 1 and 2 of R.06-04-009, with the California Air Resources Board ("CARB") having the primary implementing authority for AB 32. PG&E has been involved extensively in R.06-04-009 and is hopeful that the Commission's decisions in that proceeding will balance goals of reliability, environmental responsibility, customer costs, and administrative simplicity.

Among other characteristics, SB 1368 mandates that the EPS:

- Applies to all LSEs;
- Applies to contracts of five years or greater and to facilities with an annual capacity factor of 60% or greater;
- Deems compliant all combined cycle gas turbine units ("CCGT") permitted before June 30, 2007;
- Will be re-evaluated when an enforceable cap is in operation; and
- Will be based on the GHG emissions rate of a CCGT.

Based on the Commission Staff's final workshop report, it is PG&E's understanding that the EPS may have the following characteristics once the final decision is adopted in January 2007:

- For IOUs, application of an up-front basis during the Commission application process;
- Facilities which fall under the standard should have a reasonably projected emission rate of 1,100 lbs/megawatt-hour ("MWh") or less; and
- Reliability, cost, and Research & Development ("R&D") exemptions on a case-by-case basis.

The EPS will prohibit long-term contracts with baseload high GHG emitting resources without sequestration. PG&E does not have, and does not currently plan to enter into, long-term contracts with such generation facilities without sequestration.

The EPS of 1,100 lbs/MWh translates to a heat rate of approximately 9,400 Btu/ kilowatt-hour ("kWh") for natural gas-fired facilities. PG&E believes that, under current and reasonably foreseeable market conditions, natural gas facilities with a forecast capacity factor of 60% or greater will have heat rates below 9,400 Btu/kWh.

The attribution of an emissions rate to unspecified resources (*e.g.*, system purchases) remains an open issue. As a result, it is unknown whether system purchases done on an aggregate or regional basis, will pass the EPS or not. PG&E currently has long-term system purchase contracts among its DWR allocated electric agreements. These contracts will expire during the planning horizon of the 2006 Long-Term Procurement Plan ("LTPP") and the replacement contracts will need to conform to the adopted performance standard.

For new long-term contracts, PG&E will be required to demonstrate the forecast capacity factor of the contracted units or facilities and, if this forecast capacity factor is 60% or greater, the forecast emissions rate. PG&E intends to produce the necessary information through the same modeling methodology used for contract valuation and will document compliance through the Commission application process. Bidders responding to future long-term requests for offers for baseload products will be asked to meet the standards set through R.06-04-009.

In addition to SB 1368, AB 32 may impact electricity procurement within the planning horizon of this LTPP. Because these regulations will be promulgated by CARB in the next several years and are not known at this time, the impacts on electricity procurement are also unknown. The significant and numerous implementation details that remain unknown include the specific form of GHG emissions regulation to be adopted; the overall level of emissions limits to be applied statewide; the sources and categories of sources to be covered by the overall limits; the use of market based mechanisms; the allocation of emissions allowances among different sources and categories of sources; and the relationship of AB 32 to any subsequently enacted regional or national GHG emissions legislation.

Regardless of these regulatory uncertainties, PG&E is committed to maintaining a portfolio emissions rate is among the lowest in the nation through aggressive pursuit of energy efficiency ("EE"), DR, and renewable generation. As shown in Volume 1, Section VI.B.5, PG&E's emissions rate of carbon dioxide ("CO_2") is anticipated to decline as a result its addition of preferred loading order resources. However, there are substantial short- and long-term uncertainties to

PG&E's GHG emissions which are outside of the control of energy procurement. In any particular year, dry hydro conditions or extended outages at Diablo Canyon Power Plant ("DCPP") will increase PG&E's total GHG emissions and emissions rate as only natural gas fired generation can serve as replacement generation. Long-term changes in demand growth and success of the Customer Energy Efficiency ("CEE") and renewables generation programs will impact PG&E's long-term emissions trajectories. Finally, MRTU, described in the next section, may add further uncertainty in generation dispatch and unspecified energy purchases.

PG&E's recommended plan may require significant revision and updating in the future to reflect the impacts and requirements of AB 32 and other GHG emissions reduction regulations in the next few years. Nonetheless, regardless of this uncertainty, PG&E's recommended plan attempts as practicably as possible to anticipate, consider and incorporate the results and priorities of AB 32. PG&E will inform the Commission and revise its procurement plan, as appropriate, to reflect the actual requirements of AB 32 as it is implemented over the next several years.

By setting out energy procurement strategies for the IOUs, the EAP has positioned the state to be on the necessary and appropriate course from an environmental perspective. Given the increased emphasis on GHG, the EAP may need to expand its focus on GHG reduction by increasing the fuel diversity of California's resource portfolio. To ensure that there are additional, beneficial alternatives available in the longer term, the EAP may need to expand its initiatives to explore technological options that could become feasible by 2020. One initiative that could be substantially expanded is the development and demonstration of new renewable energy emerging technologies to accelerate commercial viability; such as ocean and wave power, next generation concentrated photovoltaics and solar, battery storage. In addition, exploration of new baseload or enhancements to existing baseload technologies that hold promise for substantial reductions in GHG and further fuel diversity, such as hybrid renewable/gas fired combinations, "H" technology combined cycle facilities, combined heat and power technologies, fuel cells, nuclear power and integrated gasification combined cycle technology with sequestration should be researched. These types of initiatives may be a part of the significant effort underway to reduce California's GHG.

Finally, while aggressively pursuing loading order resources, the Commission should consider focusing on one GHG reduction goal consistent with state policy, rather than creating further separate set-aside targets in renewables, distributed generation, solar roofs, DR, repowering or EE. If PG&E has more flexibility in choosing among a suite of GHG reducing tools, policy objectives much more likely to be achieved at a lower cost rather than if specific targets are created in several programs.

3. Impact of Market Redesign and Technology Upgrade on Procurement Practices

On September 21, 2006, the Federal Energy Regulatory Commission ("FERC") issued an *Order Conditionally Accepting the CAISO's Tariff Filing to Reflect the MRTU*.[9] MRTU implementation is scheduled for November 1, 2007, although it is possible this date may be delayed. FERC indicated in the order that MRTU represents important, but incremental improvements to the existing market design, improves price signals for generators to allow for more efficient generation dispatch, but it does so in a way that protects customers, and should lower costs by increasing the efficiency of the CAISO's transmission grid operations. FERC explained that the most important elements of MRTU are to:

- fix market design flaws;
- eliminate infeasible schedules;
- use a more comprehensive model of the transmission grid;
- add a financially binding day-ahead market;
- adopt locational marginal pricing for suppliers and for improved congestion management;
- improve transmission rights;
- require compliance with the Long-Term Firm Transmission Rights Final Rule;
- increase bid caps incrementally;
- improve local market power mitigation;

[9] *California Independent System Operator*, 116 FERC ¶ 61,274 (2006).

- provide loads with demand response capability; and
- build upon resource adequacy.

Precise procedures to be used by the CAISO and market participants to implement MRTU are proposed for the CAISO's Business Practices Manuals ("BPM"). Two draft BPMs were released on May 1, 2006. The first full set of draft BPMs was released on July 31, 2006. Stakeholder meetings followed in August through October 2006. A second full set of draft BPMs is expected to be released by January 19, 2007, with the final drafts released on May 31, 2007. Testing of the computer systems for interfacing with the CAISO for the MRTU began on October 2, 2006.

There are a number of elements of MRTU that will impact PG&E's procurement practices or costs. Congestion Revenue Rights ("CRR") are a basic part of the CAISO's MRTU design. The CAISO has proposed that CRRs be financial obligations so that market participants can hedge sources of power to loads due to transmission congestion. The CAISO is proposing a methodology to determine the amount of CRRs available, then an allocation and auction process for distributing the CRRs, and then settling CRRs. On July 20, 2006, FERC issued its Final Rule in the docket on Long-Term Firm Transmission Rights ("LT-FTR").[10] The CAISO has begun a stakeholder process to receive input on its filing to meet FERC's LT-FTR requirements and has indicated they will make a compliance filing with tariff language on January 29, 2007. The CAISO is testing its systems for CRRs for 2008 CRRs on a seasonal and monthly basis. However, since this system does not meet all of the requirements of the FERC LT-FTR rule, changes or additions to the CRR process will still be required to provide LT-FTRs. Additionally, the CAISO is developing a BPM for CRRs. LT-FTRs and CRRs are not expected to have significant impacts on the dispatch of PG&E resources, but since they are financial obligations, they may impact payments from or to the CAISO. To the extent PG&E is unable to secure LT-FTRs/ CRRs through the allocation process, some procurement from the subsequent auctions may be necessary.

Other MRTU design elements will have additional impacts on the CAISO and market participants, including PG&E. For example, the CAISO intends to impose

[10] Order No. 681, 116 FERC ¶ 61,007 (2006).

constraints in order to ensure that the required amounts of ancillary services are reasonably distributed across the system and, if system conditions merit, it may identify sub-regions within the CAISO Control Area to ensure appropriate distribution and effectiveness of the procured ancillary services. The CAISO has not established the process to define the regions or regional targets. It is not known if or how the localized procurement of ancillary services will impact PG&E's future dispatch decisions; however, this will be established as the CAISO finalizes the remaining open MRTU design elements in 2007. After the release of MRTU, it is anticipated that the CAISO will augment the current ancillary services requirements with a Frequency Reserve Requirement ("FRR") in response to a Western Electric Coordinating Council ("WECC") initiative; potential impacts to PG&E are being evaluated.

In the event that the CAISO determines that it does not have sufficient resources committed after the close of the day-ahead market to meet its next day's forecasted load, the CAISO will run a Residual Unit Commitment ("RUC") process to commit additional capacity to be available in real time; the CAISO will be able to procure RUC zonally but has yet to establish the process to define the zones or zonal targets. The CAISO may provide for RUC self provision in upgrades after the implementation of MRTU. It is not known if or how RUC procurement by the CAISO will impact PG&E's future dispatch decisions; when the remaining MRTU design elements are completed in 2007, the full impacts to PG&E will be established.

Inter-Scheduling Coordinators trades for energy in the Day Ahead and Hour Ahead Scheduling Process ("HASP") in MRTU will be different than Day Ahead and Hour Ahead trades under the current zonal market design. Under MRTU, all trades will economically settle at their relevant market (Day Ahead, HASP) and locational price (node, hub, or Load Aggregation Point). The financial impacts of Inter-Scheduling coordinator trades will be considered in PG&E's Day Ahead and HASP scheduling decisions. In addition to the current Inter-Scheduling Coordinator trades for energy and ancillary services, MRTU will include the ability to trade Uplift Load Obligations; these obligations are the result of bid cost recovery guarantees provided by the CAISO.

Additional market design features are planned for implementation *after* the initial start of MRTU. FERC has ordered the CAISO to develop scarcity pricing; prices for both reserves and energy would increase automatically as the severity of the shortages increase. Scarcity pricing is intended by FERC to increase the participation of demand response and to further encourage LSEs to contract forward for their energy needs. Energy shortages in the CAISO markets may be more expensive to those LSEs that are not adequately hedged in the future. The CAISO must also incorporate Convergence Bidding, a process by which virtual supply can be sold or virtual demand purchased in the Day-Ahead market and subsequently settle as deviations in the real time market. The actual price differences between the Day-Ahead market and real time market will determine if the holder makes or loses money. FERC has suggested that convergence bidding mitigates market power and provides other benefits. While convergence bidding does not create either real added supply or demand, these bids do contribute to the determination of market clearing prices. To the extent convergence bidding is implemented by the CAISO, it may be necessary and important for PG&E to participate.

Currently, on a PG&E system basis, it does not appear that MRTU will significantly impact the resource planning and the majority of the procurement processes that typically happen in time frames that extend well beyond the day-ahead and day-of focus of the MRTU market changes. However, what does occur in the MRTU time frame are the least-cost-dispatch processes and decisions carried out by PG&E. In D.02-09-053, the Commission reiterated the importance and requirements to perform the scheduling and dispatch of utility portfolios in a least cost manner. In compliance with this Commission decision, and in conformance with good business practices, in the day-ahead and forward time frames PG&E dispatches resources and utilizes market purchases to address any spot portfolio requirements; both are selected in merit order based on least cost. Additionally, and as applicable, PG&E makes spot economic sales for in-the-money resources. The CAISO's new day-ahead market represents one additional option for PG&E to consider and utilize with the other existing bilateral exchanges, brokers and direct transactions in executing least-cost-dispatch. All of these markets will be used. However at this time, it does not appear that the MRTU spot market reforms and new market elements will significantly alter the results of PG&E's least-cost-dispatch process.

Based on *current* MRTU market designs, in the 2006 LTPP, PG&E is seeking Commission approval to add one new product to its previously authorized approved electric procurement products and to modify the description of one existing authorized product to assure compatibility with specific new aspects of MRTU. The new product and description modification are listed in Volume 1, Section III.A.3. In particular, PG&E requests the following:

	Product	Description(a)	Prior Authorization
27	CAISO Uplift Load Obligations	Obligations that are associated with bid cost recovery guarantees by the CAISO.	New transaction requested in Volume 2, Section I.B.2.3 Impact of MRTU on Procurement Practices

Under MRTU, the CAISO will assure bid cost recovery for suppliers selling into the CAISO markets; to the extent market revenues are insufficient to recover bid costs, for example due to unit minimum run times, the CAISO will provide suppliers with uplift payments to guarantee bid cost recovery. The CAISO will in turn collect the uplift payments through cost allocations to Scheduling Coordinators ("SC"), applied in two tiers based on net and total demand. As indicated above, MRTU will establish the capability of Inter-Scheduling Coordinator trades for Uplift Load Obligations; the use of this new market design feature will provide value to PG&E.

PG&E further requests that the Commission modify the existing approved Electricity Transmission Product description, as provided for in D.02-10-062 and D.04-12-048, to clarify that this existing product is adequate to address transmission congestion and loss aspects of MRTU. The primary feature of the CAISO's proposed market redesign is an integrated market that involves the simultaneous optimization of energy and ancillary services procurement based on Locational Marginal Pricing ("LMP") in a process that will also manage transmission congestion and transmission losses. As described above, MRTU will provide for the ability to hedge transmission losses through LT-FTRs and CRRs, which can be obtained through allocations and auctions from the CAISO and additionally through secondary bilateral trading. While similar hedging products for transmission losses do not exist at this time, these have been presented for consideration at the CAISO and may develop in the future. To address these MRTU market design features, PG&E requests a modification and clarification. The existing product description for Electricity Transmission Product should be modified to provide for secondary bilateral trading as indicated below:

Existing Product (Reference D.02-10-06 Table 1 – Authorized Procurement Products)

Transaction	Description
Electricity Transmission Products	Arranged through CAISO and with non-CAISO transmission owners. Also includes purchase of transmission rights or use of locational spreads.

Proposed Modified Description

Transaction	Description
Electricity Transmission Products	Purchase or sale of transmission rights and products. When MRTU is implemented, for example, PG&E will participate in LT-FTRs and CRR's allocations or auctions.

With the addition of the new Uplift Load Obligation Product, and with the modification and clarification of the existing Electricity Transmission Product, it appears PG&E will have sufficient Commission authority to participate in new transactions significant to the current CASIO scope of MRTU.

PG&E further requests Commission approval for new products that may be needed during the CAISO's finalization of MRTU which CAISO considers mandatory for MRTU market participation. For now, PG&E will identify these new products as "Non-Discretionary Products Required by MRTU."

	Product	Description(a)	Prior Authorization
28	Non-Discretionary Products Required by MRTU	MRTU Products, which may be created by the CAISO during the finalization of MRTU, that would be *mandatory* in order to participate in MRTU.	New transaction requested in Volume 2, Section I.B.3 Impact of MRTU on Procurement Practices

PG&E requests authority for "Non-Discretionary Products Required by MRTU" since there may not be insufficient time to seek and obtain Commission approval through an advice letter filing between MRTU design finalization and MRTU market initiation. However, if there is adequate time for such a filing, PG&E will do so.

4. Expiration of California Department of Water Resources Contracts Impact

For the most part, the power contracts that DWR procured for the benefit of the IOU's customers will expire by the end of 2012. The DWR contracts are supplied from a combination of new generation built within the last decade and a few older resources. The following table shows the capacity and the last delivery date for DWR the contracts allocated to PG&E.

TABLE VOL. 2, IB-3
PACIFIC GAS AND ELECTRIC COMPANY
DWR CONTRACTS ALLOCATED TO PG&E(a)

Line No.	Counterparty	Delivery End Date	Capacity MW
1	CalPeak Power— Panoche, LLC	12/27/2011	50.8
2	CalPeak Power— Vaca Dixon, LLC	12/31/2011	50.8
3	Calpine Energy Services, L.P. (Firm)	12/31/2009	1000
4	Calpine Energy Services, L.P. (Long Term Commodity Sale)	12/31/2009	1000
5	Calpine Energy Services, L.P. (Peaking Capacity)	7/31/2011	495
6	Clearwood Electric Company, LLC	12/31/2012	30
7	Coral Power, LLC	6/30/2010	400
8	Product Reduced Starting 7/1/2010	6/30/2012	100
9	Product Start 7/1/2002	6/30/2012	100
10	Product Start 7/1/2003	6/30/2012	175
11	Product Start 7/1/2003	6/30/2012	175
12	GWF Energy, LLC	12/31/2011	94.8
13	GWF Energy, LLC	12/31/2011	96.7
14	GWF Energy, LLC	10/31/2012	170.5
15	Kings River Conservation District	9/18/2015	97.2
16	PacifiCorp	6/30/2011	300
17	City and County of San Francisco (Estimated Capacity)	Unknown	180
18	Wellhead Fresno Cogeneration Partners	10/31/2011	21.3
19	Wellhead Power Gates, LLC	10/31/2011	46.5
20	Wellhead Power Panoche, LLC	10/31/2011	49.9

(a) State of California Department of Water Resources Determination of Revenue Requirements For the Period January 1, 2007, Through December 31, 2007 Submitted To The California Public Utilities Commission Pursuant To Sections 80110 and 80134 of the California Water Code, August 2, 2006, pp. 22-24.

Because of the age of the units supplying the DWR contracts, most of these resources are likely remain in operation after the end of the contracts, and should be able to participate in competitive solicitations sponsored by the IOUs. To the extent one of these resources is a candidate for repowering, all source solicitations will provide the owners of these units with the opportunity to continue to participate in the wholesale electricity market.

5. Energy Action Plan Goal of 33% Renewables by 2020

The Scoping Memo asked the IOUs to include information about the extent to which they will exceed the existing legislative mandate of 20% renewables by 2010 and work towards the EAP policy goal of 33% by 2020.[11] As described in Volume 1, Sections IV.C.2 and V.D, PG&E is committed to reaching its 20% renewables target and is proposing to do so in all of its candidate plans. PG&E's recommended plan continues increased renewables procurement after the 20% goal is met. However, while it intends to aggressively pursue renewable resources, PG&E believes that the Commission should not at this time establish goals beyond 20%, for the reasons set forth below.

There is, however, action both PG&E and the Commission can take to facilitate renewable energy development and the availability of additional renewable resources in the future. The ERRP that PG&E is proposing in the 2006 LTPP will facilitate the development of additional renewable resources in California and provide valuable information about the depth and quality of the renewable energy market. This information and experience gained through the ERRP can assist the Commission in later proceedings in deciding future Renewable Portfolio Standard ("RPS") direction. In addition to addressing the 33% renewables stretch goal, this section also explains in detail PG&E's request regarding the ERRP.

a. The Commission Should Coordinate Proceedings on Policy Goals, Feasibility, and Cost Before Adopting a Goal Higher Than the Current 20% RPS Requirement

PG&E has previously provided extensive comments on the EAP policy goal of 33% renewables by 2020 in its comments on the Commission's 33% Whitepaper[12] and at the California Energy Commission ("CEC").[13] In its comments, some of which are reiterated below, PG&E highlighted a number of key issues that need detailed discussion and analysis before the current 20% RPS goal is expanded. In general, policy goals, feasibility, and cost impacts must be intensively studied and discussed before any final recommendation is made on any goal higher than the current 20% requirement. There are a number of critical steps the Commission should complete before adopting higher goals.

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[11] Scoping Memo at 20.

[12] *Comments on the Draft Report Achieving a 33% Renewable Energy Target*, submitted December 1, 2005.

[13] CEC Multiyear Analysis and CEC Intermittency Analysis Project.

First, the Commission should clarify the underlying goals for expanded renewables targets and consider combining the GHG reduction and renewable achievement objectives. The Commission will be implementing rules to manage GHG emissions as part of the GHG Order Instituting Rulemaking ("OIR"). Rather than mandate a new renewables percentage for utility procurement, if the state's goal is emission reduction, the Commission could simply mandate a GHG target, and the utilities could use renewable procurement, or other options to meet the GHG target. This could allow the same objectives to be met at a lower cost to Californians. RPS goals could also be expressed in terms of reliability, fuel hedge, cost or quality of service, rather than a set amount of renewables. Having clearly defined objectives, and benchmarks as to when those objectives are met, is an important next step in RPS policy development that needs to occur before new, higher goals are adopted.

Second, the Commission should explore incentives as a more effective mechanism through which to encourage achievement of expanded RPS goals. Because the existing California RPS program is one of the most aggressive programs in the country, and because utilities are still making progress toward the achievement of a 20% RPS goal, goals beyond 20% are clearly "stretch" goals. The Commission should focus on an appropriate reward and incentive structure to encourage attainment of any stretch goal. Incentives will better align interests, and set the stage for a more collaborative and problem-solving process than would penalties, and will make achievement of stretch goals more likely.

Third, the Commission should also work with the CEC and the IOUs to explore the operational feasibility of any goal beyond 20%. The Commission should determine whether the CAISO can reliably and cost-effectively dispatch and regulate the system with higher levels of renewable generation. The Commission's White Paper was a good first step in identifying some of the operational issues, and the CEC's Intermittency Analysis Project ("IAP") has been a good technical foundation on which some of the issues can be further examined. Both the CEC and Commission should coordinate on a technical analysis of the operational impact of supporting expanded goals before setting a goal beyond the 20% target.

In addition to these steps, some of the key questions which PG&E has raised in past concerning a 33% RPS goal include:

- Have the impacts of existing contractual constraints and available power products on operational flexibility been considered?

- What attributes of new conventional resources (*e.g.*, quick start, fast-ramping, etc.) would help to make higher penetrations of renewables feasible?

- What is the incremental cost of increasing the RPS goal, including the incremental transmission needed to achieve this goal, and cost of maintaining planning and operational reserves, and providing the necessary regulation, day-ahead dispatch and mitigation of intermittency (*e.g.*, pump-storage, distributed storage, real-time curtailment, dynamic scheduling, wind forecasting, etc.)?

- How does this cost compare to the value of the objectives described above?

- What renewable resource mix will help increase renewable penetration feasibility?

- What proportion of intermittent vs. non-intermittent resources, and within intermittent resources what solar to wind ratio is operationally feasible?

- How much new renewable power will have to be imported to meet expanded targets?

- Is it technically feasible to import high levels of intermittent resources?

- How much transmission needs to be built and reserved?

- To what extent can regional Renewable Energy Credits ("REC") displace or avoid transmission investment?

- Are there sufficient resources economically available in the market to satisfy a higher RPS goal, and to what extent a higher RPS goal is simply increasing the price for the same amount of renewable supply?

- What is the impact if Federal tax credits and incentives are not renewed?

- What about the ability to finance increasingly more expensive projects with the current SEP constraints?

All of these questions should be considered before the Commission adopts a new RPS goal that is higher than the current statutory standard. While the RPS program in California has made substantial strides, it is critical that the Commission, the IOUs, and interested parties have an opportunity to review the RPS experiences over recent years and carefully consider the impacts of future goals before any changes are made to the current 20% target.

b. The Commission Should Approve PG&E's Emerging Renewable Resources Program

In the 2006 LTPP, PG&E is requesting that the Commission approve its proposal for an Emerging Renewable Resources Program or "ERRP." ERRP is a funding mechanism through which PG&E can assist in the demonstration of the commercial viability of emerging renewable technologies and resources.[14] ERRP is a critical part of PG&E's strategy to procure renewable resources beyond its 20% RPS goal by:

- Expanding renewable resource supply and lowering the long-term cost of renewable energy;
- Accelerating the time to market of promising renewable technologies and resources; and
- Providing critical feedback about the availability of new renewable technologies and resources.

The ERRP will meet these objectives by allowing PG&E to pursue pre-commercial technologies and resources that would otherwise not be available.[15] ERRP targets emerging renewable technologies and resources that are early in their development, have not yet progressed down the cost reduction curve, and can benefit from inclusion in the program by advancing the commercialization of the technology or resource. As PG&E explained in Volume 1, Section V.D.2, PG&E has already identified certain promising technologies and resources that merit further investigation and possibly support, but PG&E does not currently have a mechanism to assist with these projects beyond the work done to date under more limited funding.

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[14] The ratemaking mechanism to establish the ERRP is described in Volume 2, Section IV.F. ERRP is not intended to seek approval of Power Purchase Agreements ("PPA") or large utility ownership capital projects. Instead, PPAs, as well as large capital investment for utility ownership projects, will continue to be recovered through the advice letter and application process.

[15] The ratemaking mechanism is described in Volume 2, Section IV.G.

The ERRP will provide a mechanism for PG&E to assist in developing more of these projects, with the ultimate goal of commercializing new technologies that will provide more cost competitive and reliable renewable power to California. In the end, by assisting in the development of new renewable resource technologies, the ERRP will help California make more progress toward achieving its important, but ambitious, goals in greenhouse gas reduction and renewable energy development.

PG&E requests that the ERRP initially be authorized as a 2-year program with a maximum program budget of $30 million for two years subject to balancing account recovery. PG&E recognizes that, as with any new, innovative program such as the ERRP, the Commission and interested parties will need an open, objective mechanism for reviewing projects funded under the program and the information and benefits obtained from the program. Therefore, PG&E is requesting that funds not be expended under the ERRP prior to the filing and approval of an individual advice filing for each individual project or individual category (*e.g.*, environmental studies or resource validation). The funding would cover only third-party or external costs associated with a project; PG&E's administrative and internal costs would be funded out of existing base revenue requirements. The actual expenditures identified and approved in each advice filing during the 2-year period could take place during and after that period. In addition to prior approval pursuant to advice filings and consultation with the PRG for projects, the ERRP program would be subject to ongoing review by the Commission through periodic reports at the Commission's request. At the end of the initial 2-year funding period, PG&E would have the opportunity to seek extension and/or expansion of the program in a program advice filing, subject to public comment, and the Commission in its discretion could approve or disapprove the extended program.

(1) There Is a Substantial Need for ERRP

PG&E is currently a participant in one of the most aggressive RPS programs in the country. As PG&E continues to sign a significant number of renewable contracts, it is depleting the available pool of reasonably-priced renewable technologies and resources. Under the status quo, the lack of technological alternatives or proven resource areas means that additional deliveries are available only from increasingly costly resources that may lack the desired least-cost/best-fit characteristics. In order for PG&E to procure cost-effective renewable resources beyond the current RPS goals, the company will need to examine many new technologies and resources and work with companies to bring these technologies and resources to the market. In effect, as PG&E signs more contracts and depletes the pool of existing resources, it must also work to replenish and expand this pool of resources for future years.

Next generation renewable resources may be characterized by the innovative nature of a technological improvement, the harnessing of presently underutilized resources, or the development of physically isolated or geographically remote resource locations.

The primary aim of the ERRP is to provide assistance to promising renewables product development at the critical stage where conditions must be satisfied in order to attract capital to make the technology viable on a commercial scale. Typically, operational feasibility must be successfully demonstrated in order for the product to obtain financing and other support necessary for full-scale product development and marketing. Or, while the existence of renewable resources in a geographic area may be well-recognized, quantification of the commercial potential might accelerate development and encourage greater commercial interest in the resource. The ERRP will provide resources to move companies, technologies, and resources from product identification into the demonstration phase of product development.

The development of new products and technologies typically goes through four distinct phases: (1) Research and Development; (2) Product Introduction/Demonstration; (3) Commercial Introduction; and (4) Mature Product. In each of these phases a company faces different challenges.

In the R&D phase, the major challenges are basic research, concept origination, proof of the technology, the funding/manpower needed to conduct these activities, and the skill needed to overcome technical challenges. PG&E plans limited participation in the R&D phase and would make limited investments. PG&E is currently not positioned to conduct R&D itself and focuses on advising companies in this phase on what the market or PG&E might look for in a renewable resource. This phase is often better addressed by vehicles such as the Public Interest Energy Research program at the CEC or by venture capitalists with a more compatible risk profile.

In the Product Introduction and Demonstration phase, the key challenges include financing and completing a demonstration of the technology or product and obtaining a commercial contract with the first customer, one that is willing to take the risk of a new product and potentially pay higher prices in order to prove the technology can work in the field to achieve potentially lower costs in the future. This phase is the area where PG&E's proposed ERRP can have the most impact and where it would be focused. This phase has often been referred to as the "chasm" because it is where many promising technologies and companies fail. Often, customers will not order a new product unless the technology has been proven in the field, but reliability cannot be demonstrated without the first customer. PG&E envisions working with multiple projects to test technologies and resources at ERRP demonstration sites by providing assistance which includes obtaining site control, making it suitable for demonstrations, and potentially paying for equipment. This will allow PG&E to play the role of first customer for many of these technologies and resources that are not fully commercially ready.

The ERRP will help move technologies and resources from pre-commercial to commercial status, enabling them to cross the chasm, and replenish the supply chain with new technologies and resources. The ERRP is not meant to be a substitute for all existing funding sources but an enhancement, allowing companies to prove their technologies enough to gain access to more widely-available, traditional funding sources that reflect the reduced risk of a commercially-proven technologies.

PG&E does not currently intend to use the ERRP for the two final stages of product development – Commercial Introduction and Mature Product. In Commercial Introduction phase, the challenge is ramping up sales. ERRP is focused on developing technologies, not increasing sales after a technology is proven. In the Mature Product stage, the challenge is to keep up sales of a technology that is often outdated. PG&E's Renewable Request for Offers ("RFO") are primarily targeted at fully commercial companies, those that are ramping up sales or are offering mature products. These companies can show that their technologies are commercially capable and they usually have field-deployed demos.

(2) ERRP Is Well-Designed

As described in Volume 1, Section V.D, PG&E currently uses two mechanisms through which it procures renewable resources—Renewable RFOs and bilateral agreements. However, PG&E does not have a mechanism that can accommodate above-market, higher-risk, pilot-scale projects. PG&E's ERRP offers a process through which companies, technologies, and resources are moved from development through deployment, with the third-party or external costs to PG&E funded through the ERRP. PG&E's ERRP will include a number of critical elements.

First, PG&E will expand its current outreach efforts with additional coverage at trade shows, conferences, working groups, and other programs to identify new and emerging technologies and resources and also discuss customer and market needs. PG&E will work with the CEC, the California Clean Energy Fund and venture capitalists, and conduct additional literature reviews on promising technologies. PG&E may also conduct Requests for Information ("RFI") or conduct an Emerging Renewable Resource RFO to generate additional leads and interest.

Second, PG&E will perform an initial screen of opportunities consisting of promising technologies and resources offered by third parties or identified by PG&E that, if developed, would advance the ERRP goals. Opportunities would be evaluated by initial screening metrics using the following criteria:

- The opportunity must be an emerging technology or resource that (a) has not been proven to be commercially viable or (b) is not currently commercially operational on a sustainable basis; and
- The technology must have completed demonstrable initial research and development activities leading to near term or completed proof of the concept.

Third, if a technology or resource opportunity passes the initial screen, it will then receive a more in-depth evaluation.[16] PG&E will conduct a more detailed project/technology due diligence and assessment of need including all options described in program scope. This will often require PG&E to bring in outside support in either specific technology evaluation or site evaluation and other development activities. Potential projects will be evaluated for the applicability of development support using a number of factors which may include:

- Project Economics and Project Structure – What are the potential costs and benefits to PG&E's customers of this project? Do terms and conditions with counterparties allow for satisfactory demonstration?

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[16] If a technology or opportunity does not pass the screen, it would be removed from consideration at that time. This could mean the company has not developed its technology enough and PG&E would request that the company re-engage with PG&E at a later date. Alternatively, the company could be too mature for the program. In this case, PG&E would suggest they bid into the Renewables RFO or begin standard bilateral contract discussions.

- Acceleration of Time to Market – How will this demonstration project assist in refining the technology and accelerating bringing commercial technology to market, particularly in California?
- Viability – How likely is the project to be able to meet commercial performance standards and be successfully developed and constructed?
- Ability to Drive Down Costs – How does this demonstration help reduce the cost of future projects or exert downward cost pressure for other renewable resources?
- Addressable Market Size – How large a market can this technology address? Can lessons from this project be applied to provide more low cost renewable energy for our customers?
- Portfolio Fit – How will this technology and resource fit within the broader portfolio of energy sources for PG&E?
- Long-Term Resource Potential – How much energy can be derived from the underlying resource over time?

Each factor will be evaluated and scaled. This will allow the evaluation process across projects to be simple and transparent.

Fourth, if an opportunity passes the more detailed evaluation, a specific development plan will be established. This plan would include milestones for development, a site location for deployment, and the development of a project and transaction structure under which the company and PG&E will work together to commercialize the technology and/or resource to capture future project benefits for customers. This will also define the objective of the demonstration project and the metrics by which it will be measured over its life. For example, an objective could be the generation of electric power in specified quantities by a specified time.

Finally, once a development plan is established and implemented, PG&E will monitor the development of the project over its life. This would involve making sure interim milestones are being met and that the project remains on-track to meets its stated objective.

PG&E has used the Procurement Review Group ("PRG") extensively for advice in determining which renewable resource projects best meet customers needs. It is expected that the PRG will be equally valuable in advising on ERRP projects.

(3) Development Support Will Be Tailored to Specific Needs

PG&E is examining a number of mechanisms through which the ERRP can support projects. The ultimate choice will be made by evaluating the needs of the company and the structure that best serves those needs and the best interests of PG&E's customers. Some possible funding mechanisms include:

- Equity Investment – Provides funding that is difficult to access in the market and provides PG&E with a stake in the project (not the company), which allows more control of the project.
- Debt Financing – Limits PG&E conflict of interest and allows for highest chance for capital recovery from the owner if the project fails.
- Development Assistance or Performance of Development Activities – Leverages PG&E's knowledge.
- Resource Validation – Before new technologies are deployed, work must be done to identify the best areas and sites for resource potential. This may involve detailed studies of the resource in a given area before new technologies can be demonstrated. The market also benefits because PG&E increases knowledge of resource availability (*e.g.*, solarity, tidal flows, etc.).
- Environmental Analysis – One of the reasons renewable energy is a preferred resource is because the environmental impact is generally lower than that of fossil-fired generation. However, every form of generation has some environmental impact. An important aspect of developing a new resource base or new technology is understanding the impact that it will have on the environment. As with resource validation, this analysis may be required before a specific technology is chosen.
- Acquisition of Site Control – This will assist in helping a company locate and develop a site for a new technology.

- Equipment Purchase – Expensing equipment may be the most cost-effective way to provide customer benefits through the use of promising technologies.

(4) Program Implementation

PG&E provides the following examples of how the ERRP may accelerate, or even provide opportunities for, the introduction of a "next generation" renewable resource into the renewables marketplace. As PG&E described in Volume 1, Section IV.C.2, PG&E has already identified certain promising technologies and resources that merit further investigation and, possibly support, but PG&E does not currently have a program in place to accommodate the efforts on an ongoing basis. These examples below are intended for illustration purposes and are not intended to establish exclusive parameters for the ERRP program.

Identification and Evaluation

The ERRP must be broad based and flexible enough to enable PG&E to facilitate the development of emerging renewable resource technologies wherever they exist. As a preliminary step, PG&E will seek to identify promising resources and evaluate how commercial-scale development could be encouraged and accelerated through the ERRP. While identifying potentially feasible resources and supporting the demonstration of new technology are examples of potential projects that could be funded by the ERRP, the Commission should recognize that there are many other opportunities that cannot be identified at this time, but will arise as the technology and development respond to the global call for the deployment of renewable energy resources. PG&E also seeks to educate the marketplace about customer needs.

Resource Development

The commercial availability of renewable resources is contingent upon the availability of transmission infrastructure. As the need for renewable resources grows, developers must look beyond the regions for which well-established infrastructure exists. However, undertaking the necessary feasibility studies to justify investment in an area isolated from existing electric development, including the evaluation of resource potential to the degree required to justify capital investment, the cost of technology-specific environmental compliance, the availability and cost of delivery, and the potential market for the resultant products, are undertakings that may be deemed too risky, given the cost of such studies and the likelihood of obtaining investment capital.[17]

One of the ways in which PG&E could assist in the emergence of additional renewable resources is to undertake studies in support of the potential development of a rich new renewable resource area. For example, PG&E has already proposed to study the resource potential in British Columbia in order to determine the need for investment in infrastructure to access the resource. As another example, ERRP could fund development consultants to locate and validate solar sites, taking into account issues such as the access to transmission and the angle of terrain. This could involve conducting actual solar radiation measurements on the site over the course of 12 or more months. Similar work could be done to examine other potential resources, such as tidal power, wave energy, and biomass.

Product Demonstration

PG&E expects to partner with organizations that have access to existing sites to conduct demonstrations and development work for new renewable technologies. PG&E recognizes that some attractive sites have already been claimed by companies that are now looking for a partner to help defray costs of development for the first demonstration. In this case, ERRP could provide capital to develop the site, providing seed project financing via either project debt or equity. Alternatively, PG&E could instead purchase prototype equipment and deploy these with the help of a site developer.

Another option would be for PG&E to purchase and develop the site. If the demonstration succeeds, a longer-term agreement could be negotiated (outside of the auspices of ERRP). If the initial demonstration does not succeed, PG&E could work with other companies to test new technologies on the same site.

(5) Program Costs Are Small Relative to Benefits and PG&E Will Report on Progress

Initially, the ERRP would be a 2-year program with a maximum budget of $15 million per year.[18] Funds will not be expended without an individual advice

[17] Market dynamics may ultimately support the exploration of new resources when the capital outlay is justified by escalated prices resulting from a scarcity of renewable energy resources. However, by that time, valuable time may be lost while the steady procurement of currently identified resources creates an inevitable shortage of competitively-priced renewable resources.

[18] The ratemaking mechanism is further described in Volume 2, Section IV.G.

filing for a project or a category of costs (*e.g.*, environmental studies or resource validation). The funding would be requested for the third-party or external costs associated with a project. The actual expenditures identified in a filing during the two-year period may take place during and after that period. Program status and success will be updated through periodic reports.

There should be no doubt that the ERRP will be cost-effective given the limited expenditures in relation to the potential benefit of accelerated renewables resource development. Although the exact cost and/or benefit analysis of the ERRP is difficult to calculate given the uncertainty of future renewable availability. In Volume 1, Section IV.C.2, PG&E projects total incremental renewable purchases to be between 11,000 and 15,000 GWh over the planning horizon. The proposed ERRP budget is $15,000,000 per year with a 2-year commitment of $30,000,000. If the ERRP efforts impact the costs of RPS solicitation by less then 1 percent, it is projected that the ERRP function will pay for itself in long-term renewable energy cost savings. It is estimated that $15 million per year would enable progress to be made on approximately 3 to 6 projects per year, with costs that may range from $100,000 to $5 million per project.

Examples of the types of projects that may result include environmental, resource, and technology assessments on marine energy (tidal and wave), technology demonstrations of breakthrough central station and distributed solar technologies, biomass technologies (*e.g.*, gasification), demonstrations of the feasibility of using biofuels with conventional generation, expanded biogas utilization (dairies, wastewater plants, and landfills), and energy storage for intermittent resources (large scale and distributed, stationary and mobile (*e.g.*, PHEV)).

The study of resource areas may lead to targeted Requests for Offers (or Proposals) to identify the appropriate technology to help develop a new resource. A good example of this is wave energy. The first step in harnessing wave energy may be an evaluation of the environmental impact and resource potential at a systematically-selected site. However, once those factors are known, the next step may be soliciting proposals for technologies to harvest that potential.

The program could also help with permitting, site location, transmission analysis, technology and project feasibility assessments, transaction structuring, and purchasing of energy for small demonstration projects. By receiving approval of this program, PG&E can assist in the development of technologies and resources that may not otherwise be available.

In short, the ERRP will provide PG&E and its customers with the opportunity to directly support the development of new renewable technologies and further California's goal to encourage the development of environmentally preferred and reasonably priced renewable resources.

6. Impact of New Clean Energy Loads on Procurement

There are indications that, as a result of state and federal policies seeking decreased petroleum dependence (to both reduce GHGs and address national security concerns caused by dependence on imported oil), Plug-In Hybrid Electric Vehicles ("PHEVs") and other electric substitution technologies will begin to become more commonly used by customers in northern California between 2007 and 2016.

PHEVs, like pure battery electric vehicles, will be subject to Time-of-Use ("TOU") rates, such as PG&E's Schedule E-9 residential rate which is specifically designed to strongly encourage off-peak overnight recharging of the vehicle when PG&E has excess capacity.[19] Because of the large amount of excess generation available at night, it would take millions of PHEVs charging nightly on PG&E's system before there would be any concern about the need for additional off-peak procurement. The first manufactured PHEVs are not expected to be produced by auto manufacturers until about 2009, and then only in a few models initially (*e.g.*, Nissan and Toyota have signaled their PHEV plans, targeting 2009 and 2010, respectively; General Motors also recently announced it will produce a PHEV version of its Saturn Vue to be targeted for sales in 2010 or 2011).

PHEV purchases in PG&E's service territory are expected to ramp up gradually between 2010 and 2016 as this high efficiency vehicle option[20] becomes available on a wider array of vehicle types from a larger number of automobile manufacturers. The trajectory of PHEV penetration is likely to be similar to the influx of hybrid vehicles. For example, today— eight years after Toyota introduced

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[19] Schedule E-9, which features very low overnight rates paired with extremely high daytime rates, has been successful in largely achieving overnight charging on existing plug-in vehicles.

[20] PHEVs generally provide about three times the fuel efficiency of a standard combustion engine, and about twice the efficiency of a regular hybrid. Thus, as gasoline prices continue to climb, demand for such efficient vehicles is expected to climb as well.

the Prius in the United States—there are currently 100,000 Priuses in California (out of a total of about 23 million vehicles in the state). The TIAX report[21] projects that the "expected" level of PHEVs in California by 2015 is about 75,500, and the optimistic "achievable" level is only 1,625,000 PHEVs in California by 2015.[22] Based on these projections, PG&E does not believe that incremental procurement will be required as a result of PHEVs, at least within the 10-year period addressed in this proceeding.

In addition to the emerging PHEV technology described above, electric substitution in a wide range of on-road and non-road applications has been forecasted by TIAX to represent a potential total peak demand on PG&E's system of 250-380 MW by 2020 under TIAX's "expected" scenario.[23] These electric substitution applications will, in general, be subject to Time-of-Use rates, to encourage off-peak use whenever possible. The possible load impacts from these electric substitution technologies are generally captured in the range of PG&E's load projection scenarios, including the higher load growth projections in the Scenario 4.

California benefits in many ways when fossil fuels are replaced by clean electric technologies. PG&E introduced its Schedule AG-ICE (Agricultural Internal Combustion Engine Conversion Incentive Rate) in August 2005. This program replaces diesel agricultural pumps with electric pumps that are powered by one of the cleanest generating portfolios in the country. The result is cleaner air for the San Joaquin Valley (a federal and state non-attainment area for air quality), reduced

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[21] *See* TIAX REPORT of June 9, 2005, prepared by TIAX, LLC for the California Electric Transportation Coalition, which was submitted to the Commission as part of PG&E's General Rate Case's ("GRC") showing on Low Emission Vehicles in A.05-12-002, Exhibit 5, Chapter 11.

[22] These TIAX figures are for all of California. PG&E expects that its service territory would see about 40% of these totals. Therefore, for PG&E's service territory alone, the expected PHEVs for 2015 would likely be about 30,200, with an "achievable" level of 650,000 PHEVs potentially in PG&E's service area by 2015.

[23] The TIAX Report discusses expected market developments for other electric drive technologies in addition to PHEVs, including: truck stop electrification to avoid diesel idling, port electrification, port cargo handling equipment, electrified transportation refrigeration units (e-TRUs), airport ground support equipment, electric forklifts, low tractors and industrial tugs, electric golf carts, electric lawn and garden equipment, electric sweepers/scrubbers, burnishers, turf trucks, battery electric vehicles, and hydrogen fuel cell vehicles. These connected loads likely would be 555-775 million kWh under TIAX's "expected" scenario by 2015.

greenhouse gas emissions, improved energy security, and decreased fuel price volatility.

In addition to the environmental benefits, PG&E believes there are potential system benefits from using batteries in PHEVs and BEVs for energy storage. For example, under Scenario 3, load will not grow as much as the supply of renewable energy (after demand-side measures are implemented). Under this scenario, PG&E has forecasted approximately 37% load growth in the off-peak period and a 41% renewable resource growth during the same period. As a result, there will be more than 1,000 gigawatt-hours ("GWh") renewable energy added in the off-peak than is necessary to accommodate load growth. PHEV can be used to store some of this excess off-peak generation so that it can then be used during on-peak hours. The National Renewable Energy Laboratory has also shown that PHEVs can be used to increase the amount of intermittent resources that can be accommodated on the electric system.[24]

PG&E supports and continues to show leadership on clean electric substitution development and demonstration. This sort of electric load growth, which substitutes for dirtier, imported fossil fuels, helps to advance environmental initiatives at the same time that it helps to support a higher system load factor. In addition, PHEVs and other electric substitution initiatives will help California meet Governor Schwarzenegger's GHG reduction targets and achieve the state's and the Commission's policy goals for addressing the urgent challenge posed by global climate change, as well as help improve our nation's security by reducing dependence on foreign oil.

[24] *A Preliminary Assessment of Plug-In Hybrid Electric Vehicles on Wind Energy Markets*, W. Short and P. Denholm, NREL/TP-620-39729, April 2006.

PACIFIC GAS AND ELECTRIC COMPANY

VOLUME 2 – 2006 LONG-TERM PROCUREMENT PLAN

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II. PROCUREMENT PRACTICES

A. Competitive Procurement RFOs

The purpose of this section on competitive Requests for Offers ("RFO") is to: (1) review the existing framework for procurement of short and medium-term generation resources as authorized in Decision ("D.") 02-08-071, 02-10-062, 03-10-062 and 04-12-048; (2) review the existing framework for procurement of long-term generation resources as authorized in D.04-12-048, including the requirement to use the Procurement Review Group ("PRG") and the Independent Evaluator ("IE"); (3) address issues raised by other parties regarding the existing framework; and (4) propose policy refinements which would improve the existing procurement framework for short-term and long-term generation resources.

1. Existing Framework for Procurement of Short- and Medium-Term Resources, Including the Role of the PRG Facilitating Short-Term Contracting

D.02-08-071, D.02-10-062, D.03-10-062 and D.04-12-048 established the framework for short- and medium-term contracting activities to fulfill Pacific Gas and Electric Company's ("PG&E") residual net short and Resource Adequacy ("RA") requirements. Specifically, the decisions:

- Authorized contract terms for up to five years for transactions entered into under the modified short-term procurement plans;
- Authorized a set of products and transaction processes to be used to fulfill short-term needs; and,
- Required PRG consultation for transactions with delivery terms greater than three calendar months or prior to responding to any generator RFB.

PG&E's current short- and medium-term contracting activities incorporate these directives. The time-period up to five years has provided flexibility to deal with upcoming supply-related issues or risks ahead of time. The list of products and transactions processes has, to date, been sufficient to achieve hedging objectives without being restrictive. In addition, consultation with the PRG members has proved useful as a means of communicating and receiving feedback on proposed transactions. Therefore, PG&E believes that the framework is an effective way to manage short- and medium-term needs. However, due to increased market volatility and opportunities, in the 2006 Long-Term Procurement Plan ("LTPP"), PG&E is proposing refinements that will further improve the framework in the future.

PG&E requests that PRG consultation only be required for transactions with a term greater than six calendar months. This would modify the current three-month requirement. The reason for this proposal is that with increased market volatility, PG&E has found it at times necessary to act quickly in order to mitigate sudden and significant price changes in the forward markets. Even though consulting the PRG is a relatively efficient process, there are situations where delays of even a day or two could lead to unfavorable contracting terms (costs) due to rapidly developing situations, such as unfavorable nationwide weather conditions in the winter months (November-March) and catastrophic events like Hurricane Katrina. Moreover, greater liquidity in the markets up to 12 months forward means that there are more opportunities for PG&E to hedge these risks, provided that the short-term procurement framework is streamlined. Therefore, by changing the consultation requirements to six months, PG&E believes it will have the flexibility to respond to market conditions, and will not overload the PRG with discussions of liquidly traded, standard transactions.

2. Existing Framework for Procurement of Long-Term Resources

D.04-12-048 adopted the following all-source solicitation framework for procurement of long-term generation resources:

- Endorsed head-to-head competition of Power Purchase Agreement ("PPA") and utility-owned projects by ordering that candidate projects need to participate in the same all-source open solicitations to ensure least-cost/best-fit of the proposed projects;[1]
- Lifted an affiliate ban on long-term power products but adopted "guidelines & safeguards" including use of an IE. An IE is also required in resource

[1] D.04-12-048 at 124.

solicitations where there are investor-owned utility ("IOU")-built or IOU-turnkey projects;[2]

- Ordered that debt equivalence with 20% risk factor should be incorporated into a bid evaluation process regardless of whether the bid is from a fossil, renewable or existing Qualifying Facility ("QF") resource and that the Greenhouse Gas ("GHG") adder should be used as a bid evaluation component to evaluate all bids in an all-source Request for Offer ("RFO");[3]

- Encouraged IOUs to have a mixed portfolio of demand and supply side resources and combination of renewables and fossil-fuel sources as well as different ownership types;[4]

- Required IOUs to consult with PRGs for transactions with delivery terms greater than one quarter;[5] and

- Adopted the following All-Source and Renewable Portfolio Standard ("RPS") Solicitation Bidding Guidelines:[6]

  – All resources must participate in an all-source or RPS solicitation (IOU-built, turnkey, buyout, and PPA), but RFOs can be tailored to reflect specific resource needs.

  – Negotiated bilaterals are discouraged and will be evaluated on a case-by-case basis.

  – Bids should reflect total cost (generation and transmission) of delivery to load.

  – Utility-built resources selected in a solicitation will file a Certificate of Public Convenience and Necessity ("CPCN") at the California Public Utilities Commission ("Commission") that will primarily address California Environmental Quality Act ("CEQA") review.

[2] *Id.* at 2 and 120.

[3] *Id.* at 128-129.

[4] *Id.* at 113.

[5] *Id.* at 104.

[6] *Id.* at 125.

– If bids in a solicitation are too high, the IOU can terminate the solicitation, but the IOU will have to reissue another solicitation to file a CPCN at the Commission.

PG&E's current competitive procurement practices for long-term solicitations incorporate these requirements. PG&E first integrated these requirements into its 2004 Long Term Request for Offer ("LTRFO"). Specifically, PG&E's 2004 LTRFO procurement process incorporated for evaluation purposes debt equivalence, the GHG adder, and total cost of delivery to load (generation and transmission). PG&E also employed the Least-Cost Best-Fit methodology when comparing PPAs and utility-owned projects as part of its bid evaluation process, taking into account the qualitative and quantitative attributes associated with each bid.

In addition, as part of PG&E's 2004 LTRFO solicitation, PG&E contracted directly with an IE, in consultation with PG&E's PRG. The scope for the IE's responsibilities spanned all aspects of PG&E's 2004 LTRFO. The IE and his team performed a parallel, independent evaluation of all offers received, cross-checked economic analysis results between PG&E's Market Valuation Model and the IE's resource evaluation tool, compared rankings, coordinated possible revisions, reviewed the non-price assessments of each offer, monitored communications between PG&E and all Participants, participated in PG&E's executive-level Steering Committee meetings, observed and commented on the offer selection process, and provided a summary of findings to the PRG. The IE's expertise and experience contributed to the credibility and success of the procurement process. In general, PG&E and members of the PRG who subsequently participated in the Application ("A.") 06-04-012 viewed the IE's involvement as beneficial both in terms of ensuring a fair process as well as advising on the actual selection of projects.

The procurement process has also benefited from the involvement of the members of the PRG. With regards to PG&E's 2004 LTRFO solicitation, members have provided valuable insights and constructive feedback throughout PG&E's 2004 LTRFO solicitation process. PG&E met with the PRG numerous times to discuss aspects of the 2004 LTRFO evaluation (including the evaluation criteria), to explain PG&E's evaluation methodology in depth, describe and discuss PG&E's evaluation framework for credit, discuss the results of the IE's tests of PG&E's LTRFO Market Valuation Model, review how PPAs and IOU-ownership offers would be compared head-to-head, and met to discuss initial offers, final offers, the status of negotiations, and the composition of the final portfolio.

PG&E believes that the existing procurement framework for long-term generation resources described above provides for an effective process that has enabled PG&E to successfully conduct a competitive, transparent, and equitable LTRFO solicitation. PG&E's 2004 LTRFO solicitation resulted in a robust response with over 50 bids for projects totaling in excess of 12,000 megawatt ("MW") and selection of winning bidders that collectively represent a portfolio of highly efficient peaking and shaping generation technologies benefiting PG&E customers. In addition, PG&E's 2004 LTRFO solicitation provided a competitive forum for existing QFs in PG&E's service territory to participate. The success of the solicitation was also confirmed by the IE retained in PG&E's 2004 LTRFO, who concluded that "PG&E conducted a thorough and fair solicitation and acquired the best resources for meeting long-term capacity needs."[7] Finally, the Commission concurred with the IE's opinion concluding that "PG&E conducted an open, competitive and fair solicitation and contract selection process."[8]

3. Response to Competitive Procurement Practices Questions Raised in the Scoping Memo

Attachment A to the Scoping Memo raised a number of specific questions regarding the IOUs' competitive procurement processes. In this section, PG&E addresses these questions.

a. Definition of "New" Generation

The definition of "new" generation "as a project with a 30-year life that is not yet under construction" should be modified to remove the reference to a 30-year life. The life of new generation facilities will vary based on the technology employed. Thirty years is PG&E's current expectation of the life of a new combined cycle plant. Other technologies may have different expected lives. Thus, new generation should not be limited to projects with a 30-year life. In addition, "new generation" should include replacement or repowering of existing generation facilities that are reaching the end of their useful service lives.

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[7] Testimony of Alan Taylor filed in A.06-04-012, dated April 12, 2006, at 30.

[8] D.06-11-048 at 7.

b. The RFO Process Is Sufficiently Public, But One Change Is Necessary for the Approval Process

Some parties have questioned whether the RFOs are public enough in light of the new confidentiality rules. First, the RFOs and Appendices which describe the guidelines to bidders, including the term sheets, are posted publicly and are not impacted by the confidentiality rules. Moreover, in PG&E's 2004 LTRFO, in addition to the materials described above, PG&E conducted open workshops for potential bidders and provided public responses to bidder questions. The offers themselves are confidential, as is typical in all RFOs and is expected by the bidders.

Second, the review of RFO bids is also sufficiently "public." To protect PG&E's customers as well as individual bidders, PG&E cannot disclose the content of all bids submitted, it does review these bids in detail with the PRG and the IE. This process of review among non-market participants is sufficiently open and public to satisfy any concerns, while maintaining the appropriate confidential treatment expected by bidders and necessary for PG&E's customers.

Third, with regard to approval of the RFO results, PG&E generally supports the confidentiality rules, but is concerned about one requirement. Winning bidders in PG&E's competitive procurement solicitations often do not have key elements of their projects completely in place when PG&E is required to file for approval and disclose these projects' identities. Such disclosure can put the bidders at a disadvantage if key project elements such as site control or supplier contracts are not yet complete. As a result, bid prices may increase bids in anticipation of price increases due to decreased leverage with a bidder's supplier once the bidder's name is made public. To address this concern, PG&E requests that the current confidentiality rules be revised to allow the IOUs the flexibility to disclose the names of the winning bidders once key elements of the bidder's project have been secured. In its 2004 LTRFO solicitation, PG&E had the flexibility to file its application with one of the winning contracts referred to as 'Identity Confidential' because not all key elements of the project had been finalized. PG&E subsequently updated the application and revealed the name of the winning bidder, Tierra Energy, once all key aspects of the project had been completed. This process worked well. PG&E requests that this flexibility, with regards to disclosing the names of the winning bidders, be allowed in future RFOs.

c. The Commission Should Not Require Submittal of RFOs to Energy Division in Advance of a Solicitation

The Commission should not require the IOUs to submit RFOs to Energy Division in advance of a solicitation as doing so will only further burden the Energy Division and delay the solicitation process, which is already quite lengthy. Instead of adding an additional administrative hurdle to issuing RFOs, the IOUs should be required as a part of their application for approval of RFO results to demonstrate that they complied with Commission directives. In A.06-04-012, PG&E demonstrated that the 2004 LTRFO complied with D.04-12-048 including, the incorporation of the GHG Adder, the use of debt equivalence in project evaluation, and head to head comparison into its evaluation process, conferring with the PRG, employing an IE, and filing for a CPCN for utility owned projects. In future filings seeking the approval of RFO results, PG&E will continue to demonstrate as part of its applications for approval of the winning bids that its LTRFOs are in compliance with Commission directives.

In addition, the PRG is involved in developing RFOs before they are issued. Each IOU's PRG includes members from the Energy Division. Since the PRG continues to be an integral part of all aspects of each IOUs' procurement transactions, the Energy Division (as a member of the PRG) is continually informed of any upcoming RFOs and can use the PRG meetings as a forum to ask questions regarding these RFOs. Requiring a separate, formal submission to the Energy Division will only lead to delay in the RFO process.

d. The Commission Should Not Adopt Additional RFO Policies for All Three IOUs

D.04-12-048 already includes detailed RFO requirements. In addition, each IOU has submitted short-term RFO procurement plans that address requirements for shorter-term transactions. The Commission should not try to impose additional directives or requirements on the IOUs, especially given the lack of any evidence that there have been any problems or concerns about recent IOU solicitations. As mentioned, with regards to PG&E's 2004 LTRFO solicitation, both the IE and the Commission concluded "PG&E conducted an open, competitive and fair solicitation and contract selection process. We are pleased to make this finding based on the report of the IE, who monitored and critically reviewed the process, and the general consensus opinion of the active parties to this proceeding."[9] Given this, there is not at this time any reason to adopt additional RFO policies. Other than the revisions to PG&E's short-term authority (*i.e.*, from three months to six months before PRG involvement is required) and the change in the confidentiality rules regarding bidder identity, there is no reason at this point to change or add to the Commission's current RFO policies and directives, with the possibility of delay in the on-line dates of winning projects.

e. Current Procurement Framework Clearly Defines All-Source RFOs

PG&E believes that the current All-Source and RPS Solicitation Bidding Guidelines clearly encompass and invite bids from all eligible sources. PG&E received a variety of bids in its 2004 LTRFO solicitation including PPA projects, a Purchase and Sale Agreement, and an Engineering, Procurement, and Construction contract. As a result of the robust solicitation and the variety of offers, the winning bids recently approved by the Commission in A.06-04-012 represent a diverse group of contracts and ownership types. In addition, PG&E has also received a variety of bids as part of its RPS program. Since the beginning of the RPS program, PG&E has signed contracts totaling over 1,000 MW of capacity that will be capable of producing 5,600 GWh per year to contribute toward meeting PG&E's renewable targets. As described in Volume 1, Section V.D, PG&E intends to continue to aggressively pursue renewable energy through RFOs and other procurement mechanisms. PG&E does not believe any further definition of all-source is needed.

f. PG&E will Pursue Alternatives to the 50/50 Cost Sharing Provisions of D.04-12-048

PG&E believes that the cost cap and the 50/50 cost sharing adopted in D.04-12-048 serves to discourage, and in some cases may even prevent, the development of new utility-owned generation, and is not in the best interest of PG&E's customers. The Scoping Memo directed SCE to "explore alternative cost sharing possibilities with the other stakeholders, conduct meet-and-confer sessions or workshops if appropriate, and present the Commission with a cost sharing provision for any cost savings from new construction projects that is acceptable to the other

[9] D.06-11-048 at 7.

stakeholders." PG&E intends to pursue alternative proposals to the cost cap and 50/50 sharing as directed by the Scoping Memo.

B. Credit and Collateral Policies

The structure of the energy market and the composition of sellers in California have evolved since the energy crisis. Part of that evolution includes a change in the business model of sellers. Prior to the energy crisis, many sellers were well capitalized, investment grade entities. Following the energy crisis, the sellers consist of either non-investment grade entities or Special Purpose Entities (an entity that is formed for the sole purpose of generating power), each of which is required to provide a certain level of performance assurance to Buyers. In fact, the majority of bidders responding to its all-source and renewable solicitations are Special Purpose Entities. Given the volume of bankruptcy filings and subsequent contract rejections that the industry has seen over the past few years, PG&E does not take its collateral requirements lightly. In this section, PG&E responds to the three questions presented in Attachment A to the Scoping Memo. In particular, PG&E addresses: (1) whether there should be standard credit and collateral rules; (2) whether the same credit and collateral policies should be applied to each type of energy product; and (3) the pros and cons of alternative methods of managing credit risk.

1. Standard Credit and Collateral Rules

While it is possible to have standard credit and collateral rules, it may not be practical. Each IOU has developed its own credit (including collateral) policies and practices to achieve and maintain a preferred and unique risk profile regarding the transactions it executes with counterparties. To have standard credit and collateral rules across all three IOUs would require the IOUs to reach consensus on: an appropriate risk profile, acceptable credit policies and procedures; and methods for deriving forward curves, volatilities, correlations, current exposure (including mark to market for tolling contracts), potential exposure and counterparty concentration levels.

PG&E believes that reaching consensus with the other IOUs on standard credit and collateral rules would be very difficult, if not impossible. A number of elements distinguish the three IOUs from one another and these include (but are not limited to) having a different and unique: mix of suppliers, load and generation assets including legacy contracts (*e.g.*, QFs, irrigation district, etc.), tolling agreements, short-term debt capacity; and energy portfolios. Each IOU must shape and tailor its procurement approach – including its credit and collateral decisions – to take into consideration the various elements unique to each IOU. In short, standard credit and collateral rules are not desirable given the unique nature of each utility's energy portfolio. PG&E also found, through its inquiries, no examples of other regulated utilities sharing standard credit and collateral policies.

2. Credit and Collateral Policies for Procurement Types

PG&E believes that credit and collateral policies should depend on the particular aspects of each product type, and may differ for different products. Below are descriptions of some of the specific collateral requirements that would apply to various categories of transactions.

- **RPS RFOs** – Renewable counterparties are required to post a bid deposit of $3 per kW; a development and construction period deposit of $20 per kW; and 6, 9, or 12 months of expected revenue (for 10, 15, and 20 year terms) once commercial operations begin.

- **Resource Adequacy RFOs** – Resource adequacy counterparties (rated as non-investment grade) are generally required to post 25% to 33% of annual capacity payments particularly when RA is a clearly identifiable component.

- **Up to 5-year RFOs** – Medium-term transactions for conventional power products (*e.g.*, system tolls) are subject to mark to market[10] posting (this amount is generally capped). In addition, if the counterparty is below investment grade or is unrated it may be required to post an independent amount.[11]

- **New-Source RFOs** – Long term tolling counterparties are required to post a bid deposit of $5 per kW; a developmental and construction period deposit of $60 per kW; and, once commercial operations begin, the counterparty is subject to mark to market posting (this amount is capped and the cap depends on the technology).

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[10] Mark to market is the comparison of the contract value (volume times contract price) to the market value (volume times the market price).

[11] An independent amount is a flat amount of collateral posted to cover market movements between collateral calls. If the counterparty defaults in between collateral calls (collateral calls are typically made daily or weekly) and fails to post margin, the utility can use the independent amount to cover some or the entire shortfall.

- **All Source RFOs** – Longer term transactions (beyond five years) for conventional power products (*e.g.*, unit specific tolls). Counterparties are subject to mark to market posting, which is capped.
- **Short-Term Transactions** – Short-term transactions include hour-ahead, day-ahead, balance of the month, multi-month, and swing deals. Exposures from purchases and sales of power and gas are tracked daily. Collateral requirements are governed by the master agreements under which these transactions are executed.

All Source RFOs, New-Source RFOs, and Up to 5-Year RFOs all share a common credit provision—the contracts for these products all call for mark to market posting either when the plant reaches commercial operation or when the energy is to be delivered according to the contract. Some short-term transactions are marked to market; but, most short-term transactions are not subject to mark to market posting, because deliveries occur in the current month. Two products, Renewable RFOs and RA, do not have mark to market provisions.

RA products are not traded in a liquid market. The price for an RA product is negotiated contract by contract, and prices for RA products are not readily observable in the market place. Consequently, RA products are not marked to market. Transactions resulting from renewable RFOs do not have mark to market posting provisions because: (1) there are no forward curves for renewable power (or for the environmental attributes); and (2) the suppliers of renewable products prefer not to have a mark to market provision in their contracts, because such a provision makes it difficult for them to finance a project.

While all of the products discussed above present varying degrees of credit risk[12] that require some form of financial security to cover the risk, the primary method used to cover the performance risk (the replacement cost of energy) is some variation of mark to market posting. An alternative approach is to require the counterparty to post a flat amount that PG&E holds over the contract term to cover the credit risk. The posting of collateral, whether it is based on mark to market

[12] Credit Risk includes two types of risk – payment and performance. Payment risk is the risk of non-payment for goods or services sold by the utility to a customer. Performance risk is the risk that the supplier fails to provide power or gas at the contract price for a specified term and that the utility must replace the energy at a price higher than the contract price.

calculations or consists of a flat amount, is intended to mitigate the risk of loss due to a possible counterparty default.

New Source RFOs and Renewable RFOs are different from the other transactions listed above, because they involve new construction. For new construction projects, the bid deposit and the development/construction deposit are designed to fit the risk profile of this type of transaction. Both are meant to help ensure that the project is legitimate and that it is built according to the construction schedule. The amount required (per MW) under each category differ because the markets for conventional and renewable technology are different.

PG&E believes that managing credit risk for different energy transactions requires a certain level of flexibility to select the best transaction on behalf of its customers. PG&E's current approach enables PG&E to balance various risks (*e.g*. credit, operations, portfolio, etc.) and objectives (*e.g*. meeting renewable requirements) in managing its energy portfolio. Using standardized credit terms for all types of transactions could inhibit PG&E's ability to make the best decision regarding a particular transaction or set of transactions.

In summary, the credit and collateral requirements are consistent across some categories of transactions, and where they differ PG&E concludes that the current approach is appropriate given the risk profile of the transactions.

3. Alternative Mitigation Techniques

The energy industry has discussed and explored alternative methods of securing the credit risks associated with energy contracts. Some of these methods include second liens, step-in rights, insurance, risk pools, and physical clearing. A brief description of the pros and cons of each method follows:

- **Second liens** – A party grants the utility a second lien in some real property like a power plant. ***Pros***: Assuming there is residual value in the property over and above the amount of the first lien, the supplier can avoid posting collateral to cover credit exposure. ***Cons***: The asset value is hard to determine and it can fluctuate over time. In a bankruptcy the second lien holder generally is paid only after the debt of the first lien holder is satisfied. Thus, the second lien holder would only receive something if the plant's value exceeded the requirements of the first lien.

- **Step-in rights** – The supplier grants the utility a right to take over the running of the plant if the supplier is unable or unwilling to continue. ***Pros***: It gives the utility the comfort that the plant will continue to operate – thus helping to ensure the reliability of supply. It reduces the collateral requirements of the supplier. ***Cons***: This approach is largely untested in the energy industry. The contract language is very difficult to draft particularly defining the scope of the utility's rights and when the utility can actually exercise those rights. For example, one issue is the responsibility the utility would have in operating the plant with regard to the environment and equipment operation (*e.g.*, cost allocation). In addition, in a bankruptcy of the supplier, the utility may lose its rights to step-in. Thus, the practical application of step-in rights may be difficult to achieve.

- **Insurance** – The credit risk associated with the supplier is transferred to a third-party insurer. ***Pros***: The insurer is likely to be a highly rated entity and thus the risk of loss due to a default of the supplier is greatly reduced. The amount of collateral posting required of the supplier is either eliminated or substantially reduced. ***Cons***: The cost of this kind of insurance is not known. Depending on the product or required coverage the cost may outweigh the benefit. Insurance products do not cover all types of contracts and there are likely limitations on the products that leave some credit risk uncovered.

- **Risk Pools** – The credit risk is managed for an aggregate portfolio, instead of by individual counterparty. ***Pros***: This approach may reduce the aggregate credit requirements for the pool of suppliers compared to the total credit requirement for the suppliers using a stand alone approach. ***Cons***: The methodology to implement this approach is not as yet developed. Thus it is not clear how it would work in practice.

- **Physical Clearing** – The credit risk for an energy contract is transferred to a physical clearing exchange. That is, the supplier and the utility do not have a direct relationship. Instead, they are counterparties of the exchange. ***Pros***: The credit risk of supplier default would be transferred to the exchange. If the exchange were properly structured, then the exchange would have sufficient wherewithal to meet its obligations to its customers in case of a default of a supplier. The supplier would need to meet the collateral requirements of the exchange, which may prove advantageous to the supplier, because the supplier may be buying and selling with the exchange. This may allow netting of positions thereby reducing the collateral posting. PG&E currently transacts with four exchanges Natural Gas Exchange ("NGX") (physical gas at AECO), New York Mercantile Exchange ("NYMEX") (financial derivative contracts - futures and options), London Clearing House (financial derivative contracts for power and gas) and NECC (physical gas and power at PG&E Citygate and North of Path-15 ("NP 15"), respectively).

Cons: Currently, NECC, is the only exchange to clear physical power for NP 15, is a start-up. It only has a handful of energy buyers and sellers; trades fairly standardized products and limits the size and tenor of transactions. NECC has very rigorous posting requirements and some suppliers may need to post more collateral with the exchange than they would with the utility.

PG&E concludes that all of the approaches discussed above have some merit and are worth exploring in the context of the risk tolerance of the customer. Using alternative methods to mitigate the credit risk exposure under an energy contract may lower the cost of credit to the supplier. However, it may not lower the overall delivered price of power, because it is not certain that suppliers will consistently pass the savings on to the customer; and it may increase the credit risk exposure that the customer faces.

C. Independent Evaluator

The Scoping Memo requested that the IOUs address a number of questions with respect to the use and role of an IE in the RFO process. In this section, PG&E briefly discusses Commission decisions regarding the use of an IE, reviews the scope of IE involvement in PG&E's 2004 LTRFO and RPS RFOs, and provides PG&E's recommendations with respect to certain IE-related questions raised in the Scoping Memo.

1. Commission Policy on the Use of an IE

In D.04-12-048, the Commission stated that "we will require the use of an IE in resource solicitations where there are affiliates, IOU-built, or IOU-turnkey bidders."[13] The Commission outlined the expertise the IE should have, stating that

[13] D.04-12-048 at 123.

the IE should generally come equipped with the technical expertise germane to evaluating resource solicitation power products including the background to "be able to evaluate PPAs, turnkeys and IOU-builds on a side-by-side basis, be familiar with various standard contracts and industry practices, and in the case of an affiliate/IOU-turnkey power plant, be able to quickly scrutinize, examine and essentially break down bids to determine whether the various cost components are reasonable as presented."[14] The Commission also determined that the "IOUs shall consult with its IE and PRG on the design, administration, and evaluation aspects of the RFO to ensure that the overall scope is not unnecessarily broad or otherwise too narrow" and that the "IE should be able to testify as an expert witness in any associated Commission proceeding regarding upfront review of potential solicitation transactions."[15] The Commission required that the "IOUs may contract directly with IEs, in consultation with their respective PRGs" and "allow periodic oversight by the Commission's ED."[16] Finally, the Commission stated that the IE should "abide by clear conflict of interest standards."[17]

2. IE Selection and Scope in PG&E's 2004 LTRFO and RPS Solicitations

After D.04-12-048 was issued, PG&E initiated the process of selecting an IE for the 2004 LTRFO, which was already underway. PG&E identified the skills and experience an IE should possess, developed a scope of work, and considerations to use to assess conflict of interest. From the beginning, PG&E consulted with the Energy Division and the PRG in scoping the work and in selection of the IE. The Energy Division and the PRG supported PG&E's selection of the consulting company used for the IE.

Similarly, PG&E also initiated the process of selecting an IE for the 2005 RPS solicitation. PG&E consulted with the Energy Division and the PRG during the selection process. Ultimately, the Energy Division and the PRG supported PG&E's IE selection for the 2005 RPS solicitation. Subsequently, D.06-05-039 stated that "because of the complexity, importance, and potential for conflicts and disputes, we

[14] *Id.* at 124.

[15] *Id.* at 123-124.

[16] *Id.* at 124.

[17] *Id.* at 121.

also require each IOU to use an IE to separately evaluate and report on the IOU's entire solicitation, evaluation, and selection process for this and all future solicitations."[18]

In the 2004 LTRFO, PG&E set a scope of work for the IE in consultation with the PRG. The IE's scope of work included:

- Review and comment on the appropriateness of PG&E's evaluation methodology and whether PG&E implemented this methodology;
- Use of an in-house model to check the market valuation results produced by PG&E;
- Review whether the invitation to participate in PG&E's LTRFO was distributed to a wide range of bidders;
- Review the consistency with which PG&E provided information to bidders;
- Provide to PG&E, the PRG and the Energy Division periodic presentations of the IE's findings; and
- Be available to testify as an expert witness in any associated Commission proceeding.

The IE in PG&E's 2004 LTRFO provided all of these services. In general, PG&E and members of the PRG who subsequently participated in A.06-04-012 viewed the IE's involvement as beneficial both in terms of ensuring a fair process as well as in the actual selection of projects.

In addition to the IE's scope of work identified in D.04-12-048, with regards to PG&E's RPS solicitations, D.06-05-039 stated that:

- The IE separately evaluate and report on the IOU's entire solicitation, evaluation, and selection process;
- The IE's preliminary report should be provided with the IOU's short list; and
- The IE's final report should be provided with the advice letter for approval of selected bids.

[18] D.06-05-039 at 46.

3. Response to IE-Related Scoping Memo Questions

The Scoping Memo raised a number of specific questions related to the use of an IE in competitive solicitations. With regard to whether an IE should be required in all competitive solicitations, PG&E believes that an IE should be used in long-term solicitations (*i.e.*, longer than five years) and RPS solicitations, but not in short-term and medium-term solicitations. With regard to review of short-term and medium-term solicitations, use of an IE is not needed to assess utility-owned bids and PPAs, and the quick turnaround nature of these RFOs and the magnitude of these transactions are not materially sufficient to warrant the increased level of review and likely increased time inherent in the use of an IE.

For long-term solicitations, an IE is beneficial when affiliate transactions, utility-owned or utility-turnkey bids are involved. An IE's participation provides assurance to solicitation participants that the likelihood of a bid's success is about the same whether the form of the bid is a PPA with a non-affiliated entity, a PPA with an affiliated entity, a purchase and sale agreement, or an engineering, procurement and construction contract. Employing an IE when the potential for an ownership interest exists has a number of benefits. First, it is likely to increase the quality and quantity of bids, providing for a more competitive process, all else equal. Second, the IE's representation that the RFO process was fair and projects chosen were generally the best set of projects reduces the uncertainty that specific projects may not survive the regulatory approval process. Finally, IE's report at the conclusion of the process provides an impartial record of the RFO process, enhancing transparency. For long-term RFOs when there is no ownership interest, use of an IE should be optional on the part of the utility because there is no conflict of interest in such a RFO.

With regard to IE impartiality, the IOU, the Energy Division, and PRG must balance the cost and expertise that a candidate IE brings to the solicitation process and any perceived conflict the IE may have. These perceived conflicts can take two forms: (1) a financial interest in the IOU or any potential bidder; and (2) any consulting work that the IE may have done recently for the IOU or any potential bidder. Such activities should not categorically disqualify a candidate IE, since the pool of highly qualified firms that provide this service may be greatly reduced. Instead, the IE should be obligated to fully disclose any financial interest and the date and scope of any previous work performed for the IOU or potential bidder. This information then becomes part of the consideration used for selection of the IE for a particular solicitation.

Finally, with regard to the costs and benefits of using an IE, the costs of the use of an IE fall into three categories. They are the direct cost of the IE services, any incremental time needed to bring the IE on board and involve the IE in the RFO process, and any incremental work required of the bidder to assist the IE in his scope of work. The IE's direct costs are easily quantified by reviewing the scope of work and contract dollars amounts for the contract for each RFO. The incremental time needed to bring IE on board may ultimately delay the commercial on-line dates of successful projects in a particular RFO. Such a delay may include upward pressure on short-term procurement costs as well as an adverse impact on reliability. For any particular RFO, such costs may range from zero (because there is no incremental delay) to quite significant if there is a delay and if market prices rise or reliability consequently suffers. The risk that prices may rise and reliability suffer underscores the importance that any incremental delays be avoided or at least be minimal. Direct contracting by an IOU with an IE helps minimize any such delays and should be used in the future. Incremental costs to a bidder may take the form of providing additional copies of bid materials for the IE's use or responding as part of the solicitation process to questions generated by the IE. These incremental costs in most instances are likely to be small, but may also be reflected in a participant's bid price.

Despite some cost, use of an IE has many benefits. These include a general perception on the part of the bidder community that the process will be fair and the prospect of timely Commission approval is better. This will increase participation and may exert downward pressure on bid prices. The IE may also identify errors as the RFO process moves forward. There is a large amount of very detailed work that needs to be produced as all parties participate in the RFO process. Review by the IE, particularly during these high workload periods, may find errors made by the utility or by the bidder. Finally, the IE report at the end of the RFO process helps improve transparency and provides a good foundation for subsequent RFOs.

D. Implementation of AB 1576

Assembly Bill 1576 ("AB 1576") seeks to encourage the repowering or replacement of aging generating facilities in California with more efficient, cleaner facilities. Such sites can be extremely valuable, and, with their advantages, including existing infrastructure, as well as social and environmental aspects, should be competitive with new projects. There should be numerous potential repowering projects in the state, including several legacy sites with retired units in PG&E's service territory. PG&E supports repowering efforts to the extent they are in the customers' interests and result in efficient and cost-effective projects.

AB 1576 provides assurances that regulated utilities will recover their costs of contracting with a repowering project if the project is needed for local area reliability and will provide its output on a cost of service basis plus a reasonable return. To recover the costs of the contract in rates, the contract must meet the following criteria:

(1) The project is a replacement or repowering of an existing generation unit of a thermal power plant;

(2) The project complies with all applicable requirements of federal, state, and local laws;

(3) The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities;

(4) The project will result in significant and substantial increases in the efficiency of the production of electricity;

(5) The CAISO or local system operator certifies that the project is needed for local area reliability; and

(6) The project provides electricity to California customers at the cost of generating the electricity, including a reasonable return on the investment and the costs of financing the project.

Existing sites should be less difficult to develop than new sites because of existing infrastructure and land use zoning, and should, therefore, result in a contract price lower than that possible under a greenfield project. Other advantages to repowering projects include the potential to create emissions reduction credits by shutting down the existing facility, depth of knowledge about the existing site, minimized disturbance to potentially environmentally sensitive areas, and the fact that the plant operations staff is already in place.

In practice, repowerings are subject to limitations caused by external constraints and existing project economics, such as the cost of decommissioning and demolition of existing facilities, any environmental remediation required by the previous operations, and more expensive construction costs due to the need to construct in an operating facility. In addition, significant changes to a site's cooling scheme can reduce a repowering project's competitiveness. Some sites in California were selected on the assumption of once-through-cooling. If that is eliminated, the remaining advantages are the existing gas and electric infrastructure.

PG&E believes that all-source solicitations are the best means to compare repowerings to greenfield projects. To the extent that a repowering project can use existing infrastructure and other advantages listed above, it could have an advantage over greenfield developments, and therefore should be competitive in an all-source solicitation. In its previous all-source solicitation, PG&E did include repowerings as eligible resources. PG&E will continue to encourage repowerings to participate in its all-source solicitations for new generating facilities. This competitive process sets a market price for new generation. Repowering should not be given a preference to other sources in a solicitation. Instead, to the extent repowerings are uncompetitive in a solicitation, PG&E believes it should retain the ability to determine whether contracting for such projects is in the best interest of its customers.

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SECTION III – RISK MANAGEMENT PRACTICES

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III. RISK MANAGEMENT PRACTICES

A. Gas Hedging Strategies for Electric Procurement Portfolios

The investor-owned utilities ("IOU") currently conduct gas hedging procurement: (1) for their California Department of Water Resources ("DWR") electric supply portfolio through Gas Supply Plans filed semi-annually; and (2) for their non-DWR electric supply portfolio through their procurement plans. In this section, PG&E responds to several questions raised in the Scoping Memo regarding gas hedging strategies.

1. Consistency Between DWR and Non-DWR Gas Hedging and Suggested Modifications

Pacific Gas and Electric Company ("PG&E"), by design, uses the same gas hedging strategy for its DWR and PG&E (non-DWR) electric fuel portfolios. The only inconsistency has been the timing of plan approval and implementation. DWR Gas Supply plans are submitted to DWR and filed with the California Public Utilities Commission ("Commission") on a semi-annual basis and PG&E Electric Portfolio Gas Hedging Plan ("GHP") updates are filed on an as-needed basis. Despite the differing schedules, PG&E has been able to align implementation of the plans in 2006.

PG&E would prefer to update its gas supply and hedging plans for both portfolios on an annual basis corresponding with the "gas year" which runs from November through October. This schedule would make it easier to ensure consistency between the two portfolios. This schedule would also align with DWR's revenue requirement determination cycle. Of course, PG&E recognizes that DWR would need to agree to changing its Gas Supply Plan requirement from semi-annual to annual and that the Operating Agreements between DWR and the IOUs would have to be amended. PG&E is willing to work with DWR to make such an amendment and to file it with the Commission.

2. IOU Shared Gas Hedging Strategies

PG&E would not support sharing of gas hedging best practices or strategies among the IOUs. Sharing best practices requires the utilities to disclose their hedging strategies to each other and possibly to other market participants. Disclosing an IOU's hedging strategy to other market participants puts that IOU at a disadvantage in the market and will result in higher prices for that IOU's customers.

Moreover, sharing gas hedging best practices may have limited value because the IOUs have different portfolios. Gas hedging strategies that effectively manage risk for one IOU may not be effective for another IOU. For example, if IOU A had a large percentage of tolling agreements and utility-owned generation in its portfolio (such positions are spread options) and IOU B had a large percentage of must-take resources (including renewables) in its portfolio (such positions are forwards), then a gas hedging strategy by IOU A to reduce its risk could have the opposite effect on IOU B. The impact of a hedging strategy on risk is dependent on the underlying portfolio that it is hedging.

Although PG&E does not support the direct sharing of best practices among the IOUs, PG&E does believe that the Procurement Review Group ("PRG") has a role in expressing preference for successful strategies that it has seen implemented by other IOUs. Since the PRG has access to the hedging plans and results of all three IOUs, PRG members may find particular strategies that they prefer and they can express those preferences to the other IOUs without disclosing the identity of the IOU and without disclosing any confidential information.

3. Uniform Percentage of IOU Hedging

PG&E does not support uniform hedging time horizons or hedge percentages for the IOUs. First, such an effort would require the IOUs to share their hedging strategies with each other and possibly other market participants. As stated above, this would put the IOUs at a disadvantage in the market and will result in higher prices for the IOUs' customers. Second, the IOUs have different electric portfolios, so a uniform hedging time horizon and hedging percentages may not be equally effective for all IOUs. In fact, such a strategy could be detrimental to an IOU by increasing its portfolio risk rather than decreasing it, as detailed in the previous example.

B. Application of TeVaR to Measure the Customer Risk Tolerance Threshold

PG&E uses To-expiration-Value at-Risk ("TeVaR") as a measure of unexpected increase in the total cost to its customers. PG&E's objective in managing customer exposure to price volatility is to prevent TeVaR from reaching high levels, and to reduce TeVaR when it does reach high levels.

In D.03-12-062, the Commission decided that TeVaR is an appropriate measure of risk for an IOU's electric portfolio and that TeVaR at the 99th percentile be compared to the amount of incremental customer cost associated with the customer risk tolerance level.[1] The decision also established the customer risk tolerance level to be one cent per kWh.[2] PG&E is required to notify the PRG when TeVaR at the 99th percentile is greater than the amount of incremental customer cost associated with 125% of the customer risk tolerance level.

PG&E currently is required to report TeVaR values to the Energy Division every month. TeVaR is reported at the 95th and 99th percentiles, for each of the next twelve forward months, for each quarter in the current calendar year and the three following full calendar years, and annually for the fourth following full calendar year. Since re-entering procurement in 2003, PG&E has learned how TeVaR for its portfolio is affected by market conditions and changing portfolio composition. PG&E and the PRG have a shared set of experiences in discussing TeVaR at the 99th percentile relative to the established customer risk tolerance level and in exploring the possible actions in managing PG&E's electric procurement portfolio.

In the Scoping Memo, the Commission suggested several possible changes to TeVaR. PG&E recommends the following two actions be taken and completed before the Commission mandates any change in the way TeVaR is used to measure and manage customer risk.

1) Energy Division work with members of the PRGs for the three IOUs to conduct a thorough review of the substantial experience working with TeVaR since the IOUs resumed electric procurement in 2003.

2) A survey be conducted on risk tolerance for each IOU's customers.

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[1] D.03-12-062, Ordering Paragraphs 2 and 5.

[2] *Id.*, Finding of Fact 10.

These two actions are necessary before any changes are made to the existing risk monitoring and reporting procedures that have been established by the Commission.

First, with regard to the Energy Division conducting a review of TeVaR experience for all IOUs, PG&E only has experience measuring and managing risk for its own portfolio. The Commission and many members of PG&E's PRG have this experience for all three IOUs. A thorough review of this experience, with an eye on lessons learned, seems a natural first step before making a change.

Second, a survey ought to be conducted of the IOUs' customers' risk tolerance. As originally envisioned in D.02-10-062, Energy Division was to conduct or sponsor a survey that was intended to elucidate customer risk tolerance.[3] The survey has not yet been performed. To facilitate learning about customer risk tolerance across the three IOUs, as well as to take advantage of economies of scale in designing and implementing a customer risk tolerance survey, it seems that Energy Division is best positioned to conduct or sponsor this survey. Properly establishing the customer risk tolerance level is a necessary precursor to changing the current metric (*e.g.*, TeVaR at the 99th percentile) to something else. It is premature to make a change to the PRG notification trigger–either in the percentile of TeVaR used to trigger PRG notification or to the customer risk tolerance level that triggers PRG notification–without firmly establishing the risk preferences of customers. Before the Commission determines a new guidance system and/or target is appropriate, the actual views of customers about their risk tolerances would be instructive in setting the target and designing the guidance system.

In addition to the two actions, PG&E requests that the Commission approve the use of forward-start TeVaR (described below) in the currently mandated monthly reporting of TeVaR to Energy Division. PG&E believes that it is appropriate to continue using rolling 12-month TeVaR and comparing it to customer risk tolerance level. PG&E also understands how having TeVaR reported for calendar years of delivery makes for convenient reporting across all three IOUs. However, because variance of cost increases as time-to-delivery increases, as well as because open positions tend to be larger for more distant delivery periods, TeVaR for the calendar year four years into the future is substantially higher than TeVaR for the next year.

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[3] D.02-10-062 at 44.

PG&E has found that "controlling" for the time-to-expiration allows for good comparison of TeVaR for different future delivery periods and that such "forward-start" TeVaR is a useful measure.

Forward-start TeVaR is the same as TeVaR except that it is computed as if the computation were made at a date in the future rather than today. The objective of computing forward-start TeVaR is to provide an estimate of where TeVaR values might be at future valuation dates. Both TeVaR and forward-start TeVaR are computed assuming the portfolio does not change between the valuation date and the delivery date. Forward-start TeVaR is computed assuming market conditions at the forward-start valuation date are unchanged from today's market conditions: forward commodity prices at the forward-start valuation date are the same as today's forward curve,[4] and the term structure of volatility (and correlation) at the forward start date has the same parametricity as today's term structure.[5] Forward-start TeVaR is what PG&E uses to forecast future values of TeVaR. At the very least, PG&E should be permitted to use forward-start TeVaR instead of the existing TeVaR metric in PG&E's mandated monthly reporting of TeVaR to Energy Division.

The following examples show how forward-start TeVaR is computed for a rolling 12-month delivery period. A simple portfolio of forward contracts is used to illustrate the current TeVaR calculation and how it is changed in computing forward-start TeVaR:

On December 1, 2006, the simple portfolio consists of two positions: (1) short 100 gigawatt-hours ("GWh") for delivery in July 2007; and (2) short 150 GWh for delivery in May 2008. In the examples that follow, TeVaR and forward-start TeVaR for this simple portfolio is approximately computed as TeVaR $\approx P \times Q \times \sigma \times \sqrt{T} \times 2.33$, where P is commodity price, Q is position, σ is volatility, T is time to delivery,

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[4] This is appropriate because the standard Martingale model of forward prices has the mean at a future valuation date of a forward price for energy at delivery time T equal to today's forward price for energy at delivery time T. See Helyette Geman, *Commodities and Commodity Derivatives: Modeling and Pricing for Agriculturals, Metals and Energy* (John Wiley and Sons 2005) at 100.

[5] By term structure is meant how volatility varies with time to delivery and delivery date. While the term structure of volatility is assumed to have the same parameterization for today and a forward-start valuation date, the volatilities themselves are different on the two valuation dates. This is because volatility tends to increase as time to delivery decreases. See Alexander Eydeland and Krzysztof Wolyniec, *Energy and Power Risk Management: New Developments in Modeling, Pricing, and Hedging* (John Wiley and Sons, 2003), page 91.

and 2.33 is the number of standard deviations that the 99th percentile point on a normal distribution is from the mean.[6]

Example 1: Current TeVaR. As of December 1, 2006, the portfolio used for the current TeVaR calculation only includes the July 2007 position, because it is the only position within the rolling 12-month delivery horizon January 2007 through December 2007. The inputs are forward price P=$70/MWh, position Q = 100,000 megawatt-hours ("MWh") short (July 2007 position), volatility σ = 46%, and time to delivery T = (7/12) years. TeVaR ≈ 70 × 100,000 × 46% × √(7/12) × 2.33 = $5.7 million.

Example 2: Forward-start TeVaR Four Months From Now. As of April 1, 2007, the portfolio used for the forward-start TeVaR calculation only includes the July 2007 position, because it is the only position within the rolling 12-month delivery horizon May 2007 through April 2008. The inputs are forward price P=$70/MWh, position Q = 100,000 MWh short (July 2007 position), volatility σ = 50% (greater than 46% because July 2007 has become four months closer), and time to delivery T = (3/12) years. TeVaR ≈ 70 × 100,000 × 50% × √(3/12) × 2.33 = $4.1 million. TeVaR is lower for example 2 compared to example 1 because, while the volatility is higher in example 2 compared to example 1, the overall uncertainty in the forward price is lower because the time to delivery is three months less.

Example 3: Forward-start TeVaR Eight Months From Now. As of August 1, 2007, the portfolio used for the forward-start TeVaR calculation includes only the May 2008 position, because it is the only position within the rolling 12-month delivery horizon September 2007 through August 2008. The inputs are forward price P=$60/MWh, position Q = 150,000 MWh short (May 2008 position), volatility σ = 40%, and time to delivery T = (9/12) years. TeVaR ≈ 60 × 150,000 × 40% × √(9/12) × 2.33 = $7.3 million. TeVaR is higher for example 3 compared to example 2 because the portfolio open position is greater and the uncertainty is higher.

The following example shows how current TeVaR is calculated for the calendar year 2008:

Example 4: Current TeVaR for Calendar Year 2008. As of December 1, 2006, the portfolio for calendar year 2008 includes only the May 2008 position,

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[6] This formula is only an approximation, and used here for illustrative purposes. PG&E's actual TeVaR calculation is based on Monte Carlo simulation using a precise representation of the cost distribution and would produce a different value for the same inputs.

because it is the only position within the delivery horizon January 2008 through December 2008. The inputs are forward price P=\$60/MWh, position Q = 150,000 MWh short (May 2008 position), volatility σ = 32%, and time to delivery T = (17/12) years. TeVaR ≈ 60 × 150,000 × 32% × √(17/12) × 2.33 = \$8.0 million. TeVaR is lower for example 3 compared to example 4 because, while the volatility is higher in example 3 compared to example 4, the overall uncertainty in the forward price is lower because the time to delivery is eight months less.

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IV. OTHER TESTIMONY IN SUPPORT OF PROCUREMENT POLICIES AND PLANS

A. The Commission Should Increase the Current Planning Reserve Margin of 15% to 17% Reserves on a 1-in-2 Peak Demand to 16% Reserves on a 1-in-10 Peak Demand

The current planning reserve margin ("PRM") is 15-17% on a 1-in-2 temperature peak demand forecast. However, for the reasons stated below, Pacific Gas and Electric Company's ("PG&E") recommended procurement plan is based on a 16% PRM on a 1-in-10 temperature peak demand forecast.[1] This section presents the basis for PG&E's proposal to procure based on a more stringent PRM, and quantifies the additional cost and reliability benefits associated with PG&E's proposal.

1. The Existing Planning Reserve Margin Does Not Cover a 1-in-10 Temperature Peak Demand Forecast

The current planning reserves do not provide sufficient margin to cover load increases due to 1-in-10 or hotter temperatures. As shown in Table Vol. 2, IVA-1, 7% of the current 15-17% PRM is needed to meet minimum operating reliability requirements and 5.1% is needed to cover normal levels of forced resource outages, leaving only 2.9% to cover changes in peak demand due higher than 1-in-2 temperatures. Additional uses for reserves include 2% of peak for regulation,[2] higher than normal forced outages, and load forecast deviations. By definition, 1-in-10 temperatures or higher happen on average 10% of the time. The current PRM is not sufficient to meet higher temperatures, such as those experienced during the July 2006 heat storm. In order to provide continued reliable service and cover minimum adverse operating conditions that are likely to happen once if not more during the

[1] The 16% PRM on a 1-in-10 peak demand forecast is approximately equivalent to a 20% PRM on a 1-in-2 peak demand forecast.

[2] Reply Testimony Of David L. Hawkins On Behalf Of The California Independent System Operator, filed August 10, 2006 in A.06-04-012, p. 10.

planning horizon of this Long-Term Procurement Plan ("LTPP"), a PRM of approximately 20% on a 1-in-2 peak demand, or approximately 16% on a 1-in-10 peak demand, is needed. The following table illustrates the inadequacy of the current PRM using data from the California Energy Commission's ("CEC") June 29, 2006 revised outlook for CAISO North of Path-26 ("NP26").

TABLE VOL. 2, IVA-1
PACIFIC GAS AND ELECTRIC COMPANY
RESIDUAL RESERVES AVAILABLE FOR ADVERSE CONDITIONS IN CAISO'S NP26(a)

Line No.		MW	% of 1-2 peak	% of 1-10 peak
1	1-in-2 Peak Demand	21,431	100.0%	
2	1-in-10 Peak Demand	22,181	103.5%	100.0%
3	15% Planning Reserves on a 1-in-2 peak	3,215	15.0%	
4	Uses of Planning Reserves:			
5	Forced Outages	1,100	5.1%	5.0%
6	Minimum Operating Reserves	1,500	7.0%	6.8%
7	Regulation	429	2.0%	1.9%
8	1 in 10 Temperature Impact	750	3.5%	
9	High Forced Outages	500	2.3%	2.3%
10	Total Uses of Planning Reserves	4,279	20.0%	15.9%

(a) See http://www.energy.ca.gov/2006_summer_outlook/documents/2006-06-30_REVISED_DEMAND.PDF. The 1-in-10 temperature impact reflects CEC's revised estimate, as explained in Volume 1, Section IV.B.2.

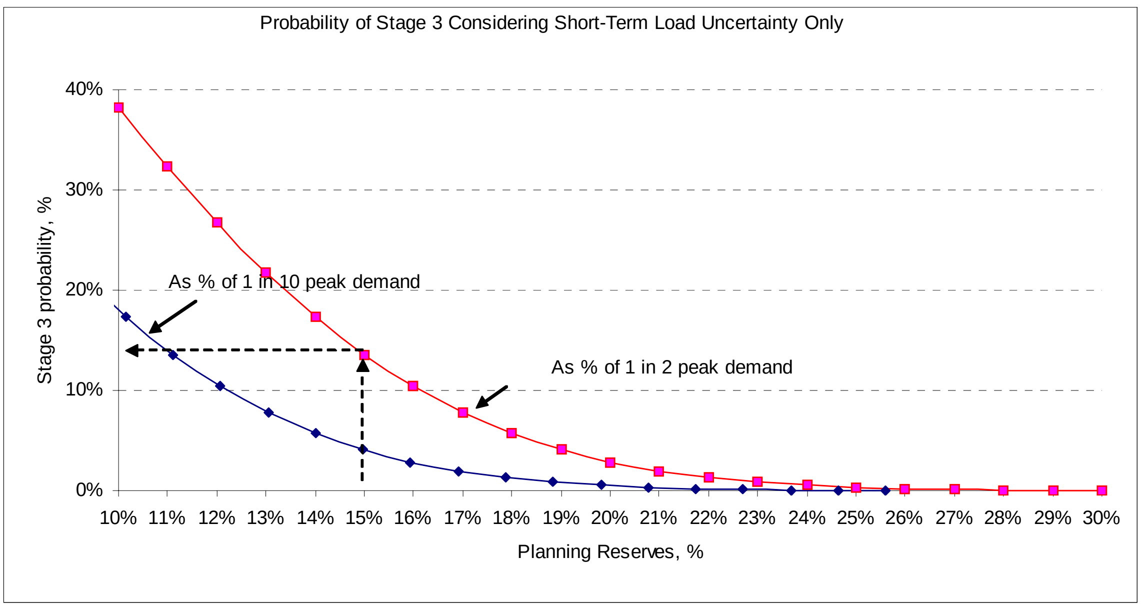
2. With the Existing Planning Reserve Margin, Stage 3 Involuntary Customer Curtailments Are Required Once Every Seven Years Considering Short-Term Load Uncertainty Alone

In addition to temperature, load projections are subject to forecast uncertainties associated with econometric variables used as input to the forecast. PG&E estimates the overall standard error of the load forecast at a 95% confidence level is approximately 10% of the peak forecast mean based on a 1-in-2 temperature.[3] For example, if the mean forecast of the 2008 peak is 21,431 MW, there is a 5% chance that the actual peak will exceed 23,574 MW (or 110% of 21,431 MW). Using this

[3] *See* Volume 1, Section IV.B.4.

estimate of the peak forecast error, PG&E has projected the probability of operating reserves being equal or less than 3% of the annual peak, at which point the CAISO invokes Stage 3 conditions or involuntary customer curtailments. The following graph shows the probability of Stage 3 as a function of planning reserves, based on a 1-in-2 temperature peak demand and based on a 1-in-10 temperature peak demand forecast.

FIGURE VOL. 2, IVA-1
PACIFIC GAS AND ELECTRIC COMPANY
PROBABILITY OF STAGE 3 CONSIDERING SHORT-TERM LOAD UNCERTAINTIES ONLY



The probability of Stage 3 events is likely higher than shown in the graph because of resource uncertainties, including the availability of intermittent resources at the time of the peak or higher than expected resource forced outages. However, even before considering the impact of resource uncertainties, the current PRM is not sufficient to cover load uncertainties at a typical 1-day-in-10 year level.

3. Considering Both Short-Term Load and Resource Uncertainties, the PRM Should Be Increased to 16% on a 1-in-10 Temperature Peak to Reduce the Probability of Involuntary Curtailments Closer to the 1 Day-in-10 Year Industry Standard

Attachment A to the Scoping Memo suggests that reliability be measured in terms of expected Energy Not Served ("ENS") or Loss of Load Probability ("LOLP").[4] Even though the LOLP reliability index is widely quoted, it does not always have the same meaning. LOLP generally refers to the daily loss of load expectation ("LOLE"); that is, the expected number of days in a year when the load exceeds the available generation.[5] The index is calculated by running multiple simulations for a given year with probabilistic representations of load and resource uncertainties, adding the number of days in the year with one or more hours of unserved energy, and then dividing that number of days by the number of simulations performed.[6] The most common utility planning standard is a 1-day-in-10 year LOLP reliability index, which is the daily LOLE multiplied by 10 (for 10 years).

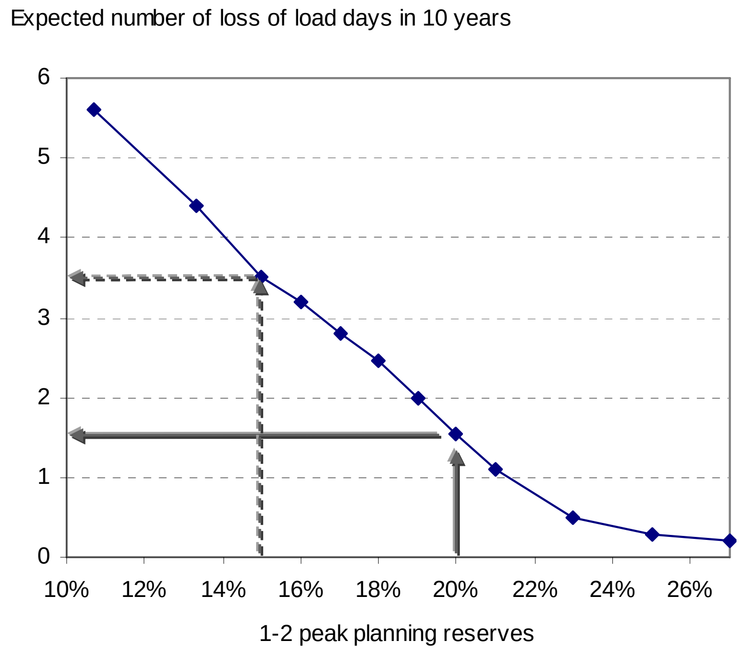
PG&E performed the LOLP analysis requested by the Scoping Memo for 2014 using different planning reserve levels. The following graph summarizes the results.

[4] Scoping Memo, Attachment A at 21.

[5] *Reliability Evaluations of Power Systems*, Roy Billinton, Ronald N. Allan, 1984, Chapter 2.

[6] The daily LOLE index does not mean 24-hour outages for each expected day that demand exceeds available generation. For purposes of calculating the LOLE index, PG&E counted the number of times that the system annual was not served. The LOLE can also be calculated hourly, in which case it is referred to as hourly LOLE. The hourly LOLE is the expected number of hours in a year when demand exceeds available generation.

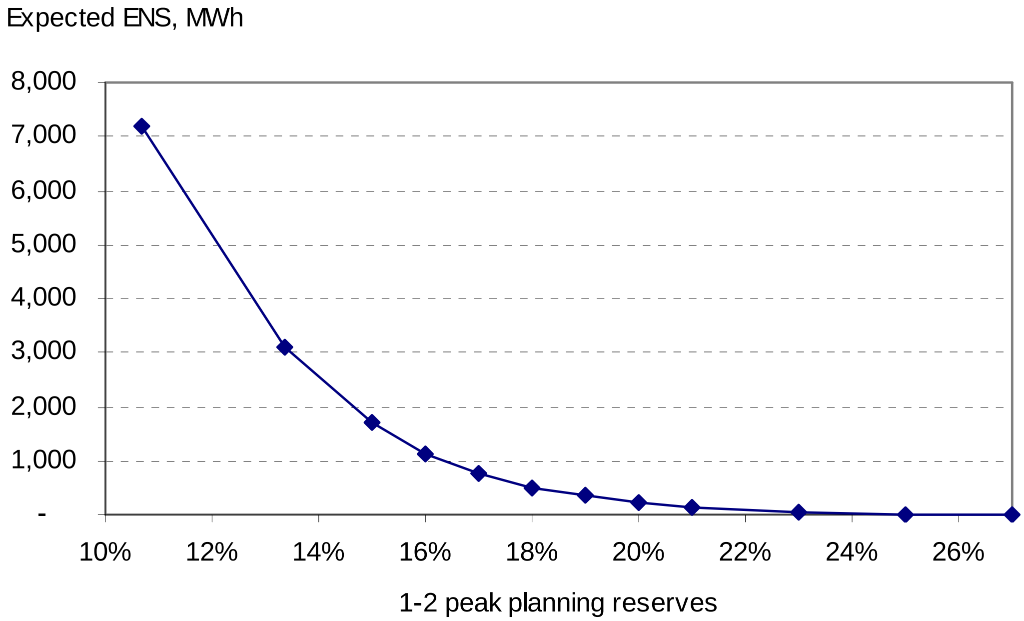
FIGURE VOL. 2, IV.A-2
PACIFIC GAS AND ELECTRIC COMPANY
1-IN-10 YEAR LOLP (EXPECTED LOSS OF LOAD DAYS IN 10 YEARS)



In order to achieve the typical 1-day-in-10 years reliability standard, the area would need to maintain slightly more than 21% planning reserves on a 1-in-2 temperature peak demand, or approximately 17% planning reserves expressed on a 1-in-10 temperature peak demand.

The LOLP index provides information about the frequency of unserved load events; however, it does not inform about the magnitude of the load not served, which is provided by the expected amount of energy not served or ENS metric. PG&E's estimate of expected ENS for 2014 for different PRMs is shown in the following graph.

FIGURE VOL. 2, IV.A-3
PACIFIC GAS AND ELECTRIC COMPANY
EXPECTED ENS, MWH



4. The Cost of Raising Reliability to PG&E's Proposed New Planning Reserve Level Is Minimal Compared to the Outage Cost and Harm to the State's Reputation

Customers incur costs during involuntary outages. According to the *2005 Value of Servic*e study that Freeman, Sullivan & Co. completed for PG&E in December 2005, the average outage cost per peak kW that PG&E customers incur (across all customer classes) ranges between $18.24/kW for a one-hour outage to $88.69/kW for an eight-hour outage, or $11.09/kWh (= $88.89/kW)/8hours).[7] A summary of outage costs by customer class in shown in the table below.[8]

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[7] The typical approach to estimate outage costs is through surveys of a representative sample of customers who are asked to estimate the costs they would experience under hypothetical outage scenarios. In those surveys customers are asked to estimate: (1) the costs they will experience during a service outage, or (2) what they would be willing to pay to avoid the outage.

[8] This study was filed in PG&E's 2007 General Rate Case on January 9, 2006 in response to Commission directive that PG&E file the results of a survey-based value of service study. Resolution E-3922, April 21, 2005.

TABLE VOL. 2, IV.A-2
PACIFIC GAS AND ELECTRIC COMPANY
AVERAGE OUTAGE COST
(OUTAGE COST BY CUSTOMER CLASS, $/KW BY OUTAGE TYPE)(a)

Line No.	Outage Type	Residential	Small/Medium Business	Large Business	Agricultural	System-Wide
1	Voltage Sag			$2.48		
2	Momentary	$0.47	$6.60	$9.72		
3	One Hour	$0.79	$39.75	$16.70	$11.86	$18.24
4	One Hour with Notice	$0.72	$28.84	$9.73	$5.47	$12.78
5	Four Hour	$1.22	$103.03	$31.12	$38.58	$45.50
6	Four Winter	$1.35			$249.97	
7	Eight Hour	$1.58	$205.77	$50.30	$75.68	$88.69

(a) Freeman & Sullivan & Co., *2005 Value of Service Study for Pacific Gas & Electric* (December 14, 2005): Table ES-2, page 3.

Involuntary interruptions and outages are undesirable, at a minimum the source of nuisance, and could lead to the loss of business or reputation. Since outage costs vary by customer class and outage duration, customers' willingness to pay could also vary widely from the system-wide averages quoted above. Outage costs can be reduced by procuring resources based on an appropriate PRM, as PG&E proposes to do in this proceeding.

In terms of the customer rate impact, PG&E's proposed higher PRM would result in PG&E procuring approximately 1,000 MW more of dispatchable or RA capacity products each year than under the current PRM. PG&E estimates the cost of this additional capacity would be between $50 and $100 million per year, depending on the year and the scenario, or a rate impact of approximately 0.1 cents/kWh. Given the minimal increase in customer cost, PG&E recommends increasing the PRM to reduce the probability of customer outages from a 3-day-in-10-year level based on today's PRM to below the 1-day-in-10-year standard.

5. Summary

As demonstrated above, the Commission should increase the current PRM to a 16% reserves on a 1-in-10 temperature peak demand, or to a 20% reserves on a 1-in-2 temperature peak demand, for the following reasons:

- The existing PRM does not cover a 1-in-10 temperature or higher load, or any other type of adverse condition;

- With the existing PRM, Stage 3 involuntary customer curtailments are required approximately once every seven years considering short-term load uncertainty alone;
- The existing PRM does not meet the typical 1-day-10 years reliability standard;
- Considering both short-term load and resource uncertainties, the PRM should be increased to at least 16% on a 1-in-10 temperature peak to reduce the probability of involuntary curtailments closer to the 1-day-in-10-year industry standard; and
- The cost of raising reliability to PG&E's proposed new planning reserve level is minimal compared to the outage cost and harm to the State's reputation.

B. Uncertainties and the Need for New Generation Resource Development

In this section, PG&E summarizes the uncertainties inherent in planning for and bringing on-line new capacity and the impact of such uncertainties on market prices and reliability. Based on this discussion, and its recent experience in Renewable Portfolio Standard ("RPS") Request for Offers ("RFO") and the 2004 Long Term Request for Offers ("LTRFO"), PG&E has identified the specific timing and amount of new resources it should seek in its next all-source LTRFO.

1. Summary of Planning and Procurement Uncertainties

As discussed in Vol. 1, Section IV.D, planning and procurement uncertainties can be placed in three categories—short-term cyclical uncertainties, long-term structural uncertainties, and commercial development uncertainties. All need to be considered when deciding when and how much new generation capacity PG&E should contract for in its next all-source LTRFO.

Short-term cyclical uncertainties are events of short duration that can adversely affect levels of demand or availability of resources. A reserve margin is established to account for these uncertainties when procuring resources. Uncertainties that affect demand are generally temperature-related. An extreme hot temperature event, like the one experienced in the summer 2006, can increase peak demand by more than 2,000 megawatts ("MW") above a 1-in-2 year, or "average," hot temperature event.

On the supply side, precipitation and other factors which affect hydroelectric generation in the Pacific Northwest and in California can affect the energy and capacity available from these resources. In addition, forced outages affect the capacity available to serve demand. Finally, although gas and electric price volatility may not significantly affect reliability, they do affect customer costs. This volatility is a function of the degree to which the cost of PG&E's portfolio moves with the volatility of gas and electric prices. Additional gas and electric energy supply is likely to have the effect of dampening market volatilities and reducing the likelihood of extended price excursions.

Long-term structural uncertainties are related to long-term demand growth, the pace of existing resource retirements and to policies adopted that affect gas and electric markets. Long-term load growth may be other than anticipated in an average case due to many factors, ranging from economic and demographic factors as well as the overall cost of electricity and gas. This uncertainty is heightened by the ability some PG&E customers may have to avail themselves of Community Choice Aggregation or Publicly-Owned Utility ("POU") procurement supply service, and other supply options such as Community Choice Aggregation ("CCA"). The pace of retirements over the next several years places additional uncertainty on the need for new resources and is particularly prominent given the current set of plant demographics, where the vast majority of the 4,400 MW of old, operationally flexible fossil units are likely to retire within the 10-year planning horizon. Policy and regulatory developments can also affect PG&E's obligations to procure new resources. These include the rules for resources to qualify for Resource Adequacy ("RA"), as well as the need for resources located in specific transmission-constrained local areas.

Finally, there are uncertainties associated with the commercial development of all new resources. While PG&E has a strong record in providing excellent Customer Energy Efficiency ("CEE") programs to its customers, the targets included in this plan are aggressive and embody more uncertainty than previous and lower levels of CEE. Demand-side management programs, particularly price-responsive programs, are also being scaled up to much higher levels. Renewables development through PG&E's RPS program has resulted in a number of new contracts and is expected to bring in additional contracts in subsequent RPS solicitations. Performance of these projects when expected depend on successful development of the projects, on-time construction of transmission to bring this power to market, and successful operation of these facilities once complete. In addition, some of these projects provide power on an intermittent basis, adding to the need for operationally flexible resources to effectively integrate these facilities as part of a reliably operating supply. Finally, more traditional gas-fired resources also face development challenges, requiring permits from as many as 16 separate federal, state and local agencies prior to operation. Such permits require resolution of land, water, visual, noise and many other issues. While transmission access for gas-fired resources may not be as critical as for renewables (because there are more options for choosing a site that has sufficient transmission infrastructure), some projects may require substantial transmission upgrades. In summary, there is significant development uncertainty associated with all resources. This uncertainty needs to be considered in PG&E's procurement planning process.

2. Recommendations for PG&E's Upcoming All Source Long Term Request for Offers

The uncertainties discussed above are substantial. Only the short-term cyclical uncertainties have traditionally been considered in operating and planning reserve margins. However, reserve targets and procurement planning also need to consider long-term structural uncertainties as well as commercial development uncertainties. The effect of these uncertainties is not symmetric. If PG&E procures too much in the way of long-term resources, electric rates may be temporarily and only slightly higher, until PG&E adjusts the level of new capacity added in subsequent solicitations. This is a temporary and relatively small adverse impact. However, if PG&E procures too few resources, or does not procure sufficient operationally flexible resources, the adverse reliability and cost impact may be large and continue until a sufficient number of new resources with the needed operating characteristics can be added. The magnitude of the adverse impact of being short is much worse than being long.

As discussed in detail in Volume 2, Section IV.A above, to address these uncertainties PG&E recommends increasing the PRM from 15-17% of forecasted load for a 1-year-in-2 maximum temperature to 16% of forecasted load for a 1-year-in-10 maximum temperature. In addition to a change in the PRM, PG&E also suggests that it procure for more than its currently projected need. In particular, PG&E proposes procuring approximately 500 MW in additional capacity through a

LTRFO, essentially equivalent to the capacity of a combined cycle plant. This proposal provides a reasonable level of insurance in the event that overall resource development takes longer than expected or that some projects simply never reach commercial operation. Given the long lead time necessary to develop a new resource, PG&E's proposal will ensure that if some planned resources do not develop, electric customers in Northern California will continue to have an adequate and sufficient energy supply.

In the 2006 LTPP, PG&E has identified a 1,800 MW need for new generation in PG&E's service area starting in 2011. In order to address the significant uncertainties described above, PG&E is proposing adding 2,300 MW of dispatchable and operationally flexible new generation resources that would come on line starting in 2011.

C. Electricity and Gas Portfolio Hedging Plan and Gas Supply Plan

1. Electricity and Gas Portfolio Hedging Plan

In Volume 1, Section III, Attachment IIIA, PG&E has presented its electric and gas hedging plans, including proposed changes to its current hedging plans. That section, incorporated here by reference, presents a detailed description of each plan and justifies the proposed changes to current practices. As part of the 2006 LTPP, PG&E requests that the California Public Utilities Commission ("Commission") approve PG&E's electricity and gas portfolio hedging plan.

2. Gas Supply Plan

In Volume 1, Section III, Attachment IIIB, PG&E proposed a strategy for procuring natural gas supply to serve its electric procurement needs. PG&E's plan is designed to meet the growing natural gas needs of PG&E's portfolio, including gas required under tolling agreements and gas need for new PG&E-owned facilities. PG&E's Gas Supply Plan provides a detailed description of, and the basis for, each element of the plan and explains why each element is necessary to accomplish these goals.

In addition, as part of its Gas Supply Plan, PG&E has proposed executing supply contracts for economic biomethane. Biomethane is a pipeline quality natural gas produced from renewable resources, such as animal waste. The promotion of biomethane will help develop a renewable fuel that can be used to produce energy that, assuming CEC certification, would qualify for renewable energy credit under

PG&E RPS program. Biomethane can provide significant reductions of greenhouse gases by capturing and converting methane, a greenhouse gas with approximately 21 times the global warming as carbon dioxide. Moreover, biomethane gas will offset PG&E's need for conventional natural gas, thus increasing overall supply to the California gas market and increasing PG&E's diversity of supply. Biomethane has a number of environmental and supply benefits, and thus should be an approved part of PG&E's 2006 LTPP.

D. Nuclear Fuel Plan

1. Nuclear Fuel Market Assessment

In Volume 1, Section III.C, PG&E presented its recommendations for prudent and cost-effective procurement of nuclear fuel materials and services during the period of 2007 through 2016. In this section, PG&E supports the recommended nuclear fuel plan by presenting its analysis of the nuclear fuel market and assessment of costs and risks associated with nuclear fuel procurement.

a. Nuclear Fuel Supply Outlook

PG&E monitors the global nuclear fuel supply and demand as a number of countries (*e.g.*, China, India, Japan, Russia, and South Korea) have announced plans for new nuclear plant construction in the foreseeable future. Over the past two years, there have been several detailed studies evaluating current nuclear fuel supply and forecasted nuclear industry demand in the next two decades. These studies are generally available to the public and referenced in the following supply outlook. Current forecasts show a world-wide installed nuclear power capacity rising 10% by 2015 and likely an additional 14% by 2025. Table Vol. 2, IVC-1, summarizes the projected global supply and demand for uranium as forecast by the World Nuclear Association ("WNA"), but does not fully account for this increase in world nuclear power capacity.[9]

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[9] The WNA is in the process of updating its forecast.

TABLE VOL. 2, IVC-1
PACIFIC GAS AND ELECTRIC COMPANY
URANIUM SUPPLY AND DEMAND FORECAST(a)
(IN 1000 LBS)

Line No.	Year	Supply Forecast	Demand Forecast
1	2006	116,290	170,230
2	2007	126,870	172,970
3	2008	134,710	173,930
4	2009	149,120	178,190
5	2010	171,730	185,950
6	2015	198,680	202,790

(a) The Global Nuclear Fuel Market, Supply and Demand 2005-2030, WNA, 2005.

Annual production of uranium will not satisfy these demand projections. The supply will meet forecasted demand only if non-traditional inventories are used, such as government stockpiles and the blend down of highly-enriched weapons material.

As discussed in Volume 1, Section III.C, in addition to uranium supply, there are two other essential services for nuclear fuel – conversion services and enrichment services. The demand for these services is also increasing and supply will likely be tight. Table Vol. 2, IVC-2, summarizes the projected global supply and demand for the conversion services segment of the market as forecast by the WNA.[10]

TABLE VOL. 2, IVC-2
PACIFIC GAS AND ELECTRIC COMPANY
CONVERSION SERVICES SUPPLY AND DEMAND FORECAST
(IN 1000 KG)

Line No.	Year	Reference Supply	Reference Demand
1	2006	69,700	61,500
2	2007	72,500	62,500
3	2008	73,000	62,000
4	2009	74,600	64,000
5	2010	75,300	67,000
6	2015	74,400	74,000

Conversion services are in balance with demand throughout the planning horizon, although there will likely be little excess capacity at the end of the forecast

[10] This forecast is currently being updated by WNA to factor in increased nuclear power capacity.

period. Expansion of capacity at existing facilities and new replacement capacity facilities are being planned to maintain a supply balance in the conversion services segment.

Table Vol. 2, IVC-3, summarizes the projected global supply and demand for the enrichment services market segment. The data has been provided factoring in anticipated demand growth due to new construction in the United States ("U.S.") and in other countries.

TABLE VOL. 2, IVC-3
PACIFIC GAS AND ELECTRIC COMPANY
ENRICHMENT SERVICES SUPPLY AND DEMAND FORECAST
(IN 1,000 SWU)

Line No.	Year	Reference Supply	Reference Demand
1	2006	47,750	45,490
2	2007	49,000	46,510
3	2008	51,000	46,360
4	2009	52,500	48,330
5	2010	53,800	50,220
6	2015	51,800	55,730

Enrichment services are in balance with demand using existing capacity and the weapons material blend down program through 2010 and by 2012, but switches to a supply short market based on several coincident events. Projections account for the transition of facilities from gaseous diffusion to gas centrifuge technology in the 2009 to 2013 time frame. Should this technology transition be delayed due to construction, equipment or facility startup issues, the balance between supply and demand will be disturbed. The weapons material blend down program between the U.S. and Russia ends in 2013. This program supplies both uranium and enrichment services to the global market and its end without a follow-on program will also impact the market supply.

b. Fuel Price Forecasts

Based on the forecasts above, uranium and enrichment market segments will be in an unbalanced condition between supply and demand for the next 10 years. This imbalance is reflected in varied pricing forecasts. Market imbalance encourages utilities to be conservative and more heavily rely upon security supply principles.

This creates a market where the buyers will act in the near term to secure contracts for longer-term deliveries.

PG&E's long-term nuclear fuel plan is designed to address the primary objective of the security of supply. Prices for material deliveries are being negotiated to provide reasonable costs at the time of delivery based on the existing market conditions at the time of contract execution. By using the best available forward price forecasts for future material deliveries, PG&E can approximate the prices at delivery and negotiate accordingly. Contracting forward with forward pricing will be evaluated and managed through either cost averaging or other hedging mechanisms. Since the nuclear fuel market is very limited in suppliers and buyers, the financial markets have been slow in developing financial tools to address price volatility. PG&E anticipates that this condition will change over the coming years.

2. PG&E Proposed Strategy on Supply and Price Risk Management

This section summarizes the nuclear fuel plan presented in Volume 1, Section III, Attachment IIIC and explains the benefits of the plan's methods to mitigate risk.

a. Nuclear Fuel Market Assessment

To assure security of supply, the nuclear fuel plan is designed to cover the Diablo Canyon reload requirements for the period 2007-2016. Supply security assures that there will be a reduced possibility of electricity production delays due to a lack of nuclear fuel. Unlike other fuels such as natural gas, there are few sources for PG&E to obtain nuclear fuel services and a very limited supply. The Diablo Canyon Power Plant ("DCPP") cannot run without fuel and an interruption in fuel supply would be devastating. Thus, the primary objective in PG&E's nuclear fuel procurement plan is to ensure that PG&E procures an adequate supply of fuel and fuel services. With the forward fuel supply under contract and secured, PG&E will be able to monitor the fluctuations of the market and negotiate supply adjustments. It also allows PG&E to address changes in future nuclear fuel demand due to new power plant construction throughout the world, which will influence both market supply and price. The best position to take in the nuclear fuel market at this time is to assure security of supply while the opportunity is available.

b. Supply Risk Management Strategy

One of Fuelco's[11] main objectives is to support the fuel procurement activities of its members. This is accomplished through the consolidation of member fuel supply needs and the solicitation of the market for those needs to attract the best offers. Fuelco's strategy is consistent with that of PG&E, security of supply through diversity of suppliers. PG&E's nuclear fuel plan will assure that PG&E is fully supplied with nuclear fuel for the 2007-2016 time period. This strategy is superior to current practice in two ways. First, by participating in the Fuelco strategic inventory of enriched uranium, PG&E will address the possible non-delivery of enriched uranium to PG&E's fuel fabricator by maintaining the inventory in a cost-effective manner at the fabricator.

Second, the utilization of diverse suppliers for uranium, conversion and enrichment reduces the risk of final fuel delivery that DCPP could be impacted by a supplier non-delivery. PG&E maintains the general position that working with a supplier to assure delivery is preferred to not receiving the contracted material delivery. This could involve adjustments in schedules and quantities to address supplier problems, if they arise.

c. Price Risk Management Strategies

PG&E's nuclear fuel plan also achieves favorable pricing of fuel and service contracts by utilizing a combination of two pricing methods to balance the costs of fuel components in the forward-pricing format of nuclear fuel supply contracts. [redacted]

[11] Fuelco is a partnership between Union Electric Company (d/b/a/ AmerenUE), TXU Generating Company LP and Pacific Energy Fuel Company (a wholly-owned subsidiary of PG&E) providing services in the areas of nuclear fuel procurement, contract administration and fuel fabrication support.

[redacted]

PG&E's nuclear fuel plan utilizes a combination of forward- and base-escalated pricing to purchase the necessary nuclear fuel supply to assure security of supply, and provide, a reasonable composite total fuel cost for recovery through the annual Energy Resource Recovery Account ("ERRA") proceedings.

3. Plan Summary and Recommendation

PG&E proposed its nuclear fuel supply plan to mitigate the risks discussed above and assure adequate security of nuclear fuel supply. The necessity for this forward contracting is established in the discussion in this section and is based on the uncertainty in the nuclear fuel supply market. Pricing and cost impacts will be managed through tools being developed by the industry as well as PG&E's oversight of the nuclear fuel supply market indicators and forecasts. In summary, the nuclear fuel supply plan requests Commission approved of the following:

- Forward contracting for full reload requirement coverage (*i.e.*, uranium supply, conversion services and enrichment services) using the contract duration and pricing structure described in the plan; and

- Participation by PG&E in the Fuelco strategic inventory of enriched uranium.

To the extent PG&E needs to modify this nuclear fuel plan after the 2006 LTPP is approved, it would do so through the timely submission of an advice letter.

E. Ratemaking Proposal for D.06-07-029 Cost Allocation Mechanisms

The purpose of this section is to establish cost recovery mechanisms for new generation resource PPA investments subject to the cost allocation provisions of Decision ("D.") 06-07-029.

1. Background

In July 2006, the Commission issued a decision adopting cost recovery for new generation investments. That decision, D.06-07-029, adopted a cost allocation mechanism to be applied to new generation investments secured by an IOU through a Purchase Power Agreement ("PPA"), but deferred the implementation details of the cost allocation mechanism to Phase 2 of this proceeding.[12] The D.06-07-029 cost allocation mechanism was adopted to ensure that the costs of new generation investments would be allocated to all benefiting customers, so that an IOU's bundled customers would not bear the sole responsibility for new generation investments that provide system reliability benefits.[13] The methodology is to be in place for the term of the qualifying PPA or 10 years, whichever is shorter, from the time the new unit comes on line.

Under the D.06-07-029 cost allocation methodology, the energy and capacity from the new resources is "unbundled," and each Load-Serving Entity ("LSE") in an IOU's service territory is allocated rights to the capacity that can be applied to satisfy its RA requirement. The LSE's customers receiving the benefit of this additional capacity pay only the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with the contract.[14] The energy is to be separately auctioned to maximize the value and minimize the net cost. The auctions are to be periodic, so as to capture the fluctuations in the energy market. D.06-07-029 deferred a final decision regarding the details of the energy auction until Phase 2 of this proceeding. PG&E and other IOUs submitted their auction proposals on October 20, 2006, and then participated in a November 1 workshop to discuss the energy auction. On November 17, 2006, ALJ Carol Brown scheduled additional workshops and briefing to address energy auction proposals, and a Commission decision is expected in 2007.

Under the D.06-07-029 cost allocation methodology, the utility is to make an election of this cost allocation mechanism at the time it submits its application for approval of the contracts. However, for the five PPAs PG&E submitted in its 2004 LTRFO application, PG&E has requested that the Commission allow it to defer its

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[12] D.06-07-029, Conclusion of Law 10.

[13] *Id.*, Conclusion of Law 2.

[14] *Id.*, Conclusion of Law 7.

election of this cost allocation mechanism until after the Commission issues a final decision in this proceeding concerning the energy auction. On November 30, 2006, the Commission approved PG&E's 2004 LTRFO contracts and accepted PG&E's proposal to defer the energy auction election.[15]

2. Definition of "Benefiting Customers"

Under D.06-07-029, benefiting customers are defined as follows:

> Customers benefiting from new generation investment secured through PPAs include bundled service customers, direct access customers, community choice aggregation customers, and others who are located or locate within the distribution service territory of an IOU but take service from a local publicly owned utility subsequent to the commitment date for new generation.[16]

> Customers whose load is displaced by an on-site or over-the-fence distributed generation unit after a new resource commitment is made also benefit from these new resource commitments and are not exempted from this charge.[17]

Accordingly, customers benefiting from the five PPAs approved in PG&E's 2004 LTRFO should be those as defined above as of March 31, 2006, the approximate date that PG&E executed those contracts.

3. Methodology to Allocate Net Costs and Benefits for New Generation Secured Under Provisions of D.06-07-029

The following section sets forth the methodology to be used to allocate the net costs and benefits for new PPAs subject to the allocation principles established in D.06-07-029. Should PG&E elect to apply this cost allocation methodology to the five PPAs secured through the 2004 LTRFO, or future PPAs as authorized by the Commission, the following process would be implemented.

The inputs to the cost allocation and definitions are shown below.

Inputs to Cost Calculation

1) **Fixed Costs:** Under a PPA, fixed costs include Unit Capacity Payments, Fixed Operations and Maintenance ("O&M") costs and any other costs that do not vary with plant output.

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[15] D.06-11-048, Ordering Paragraph 21.

[16] D.06-07-029 at 25, footnote 21.

[17] *Id.*, Finding of Fact 35.

2) **Variable Costs:** Variable costs include all costs that vary with a unit's output. These costs include, but are not limited to, unit fuel costs, unit start-up costs, unit shut-down cost, and California Independent System Operator ("CAISO") costs.

3) **Market Value of Energy:** Determined based on either an energy auction**,** or, in the absence of a successful auction, under the Joint Parties' proposal as described in D.06-07-029.

4) **Market Value of Ancillary Services:** Determined based on either an energy auction**,** or, in the absence of a successful auction, under the Joint Parties' proposal as described in D.06-07-029.

Inputs to Benefits Calculation

RA Benefits: The RA benefits of the new generation PPAs will be allocated among benefiting customers, consistent with the provisions of D.06-07-029. RA capacity credits are to be divided among LSEs by a share of coincident peak (referred to as the 12-cp method), adjusted on a monthly basis to facilitate load migration.

To implement the D.06-07-029 cost allocation methodology, PG&E will need to annually forecast the net cost of the new PPAs each year and establish a balancing account that will record, on a monthly basis, the difference between revenues collected through an auction or based on the Joint Parties' valuation proposal, whichever is applicable, and the actual costs of the new generation PPAs.[18] Any under- or over-collection in the balancing account would be reflected in the following year's forecast of net costs to be allocated and recovered from all benefiting customers. Rates to recover the net cost would be revised each year. The net cost forecast would be allocated to each group using the same 12-cp method used to allocate the RA benefits. Rates would vary by customer class and would be determined on a cents per kilowatt-hour ("kWh") basis.

To ensure that PG&E recovers only the total net cost of the new generation PPA from the benefiting customers—no more and no less—it proposes to establish the NCBA, through which it will recover the net costs of the new PPA from all benefiting customers including bundled customers, and to make appropriate off-

[18] Where the CAISO Day-Ahead nodal price is used to determine the forecast of market revenues, a true-up to actual CAISO Day-Ahead prices will be necessary. This true-up of imputed market revenues will be captured in the annual amortization of any over- or under-collection in the Net Cost Balancing Account ("NCBA").

setting entries to the ERRA, for which only bundled customers pay. An illustrative example of these entries is presented below.

Illustration of Net Cost Balancing Account, Its Interaction With Other Ratemaking Accounts and Illustrative Cost and Benefit Allocations

The key inputs to the NCBA cost calculation are: 1) the PPA annual cost forecast and 2) the annual revenues derived from the marketplace, whether through auction or using the CAISO Day-ahead nodal price.

For purposes of the illustration below, assume the PPA(s) total cost annually for both energy and capacity is $650 million. The total revenues from the marketplace for the energy component of the contract, whether through auction or using CAISO day-ahead nodal prices, are assumed to be $368 million. The resulting net cost to be recovered through the Net Cost Balancing Account would be $282 million ($650 million - $368 million = $282 million).

To ensure that customers pay only the $650 million that PG&E is contractually obligated to pay under the contract terms, PG&E would need to make an adjustment to the forecast revenue requirement in the ERRA Account to ensure that bundled customers are not charged twice for the contract. For example, PG&E would include in its annual ERRA forecast the $650 million total contract cost for the PPAs, pursuant to the ERRA tariff language. An offsetting entry would be made for $282 million, reducing the ERRA revenue requirement by an amount equal to what is recovered through the NCBA from all benefiting customers. The amount remaining in the ERRA forecast attributable to the PPAs would be $368 million if the energy is not auctioned off. If the energy is auctioned off, PG&E would not reflect the cost of this contract in the total ERRA forecast.

Once the NCBA amount is determined, the costs and benefits are allocated using the 12-cp method to all benefiting customers. An illustration of the allocations is presented in the following tables using the illustrative numbers above and assuming total sales from PG&E's Generation Rate Case Test Year ("GRC TY") 2011 sales and that non-bundled sales are approximately 11% of PG&E's GRC TY 2011 sales:

TABLE VOL. 2, IVD-1
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE COST ALLOCATION RATES

Line No.	Customer Class	Illustrative Cost Allocation ($/kWh)
1	Residential	$0.00355
2	Small Light and Power	$0.00361
3	Medium Light and Power	$0.00315
4	Schedule E-19	$0.00315
5	Streetlights	$0.00189
6	Standby	$0.00156
7	Agriculture	$0.00234
8	Schedule E-20	$0.00257
9	Total	$0.00319

TABLE VOL. 2, IVD-2
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE RESOURCE ADEQUACY REVENUES AND BENEFITS

Line No.	Customer Class	Bundled Load Allocated Benefits ($1,000)	Other Benefiting Customer Allocated Benefits ($1,000)
1	Residential	$114,856	$324
2	Small Light and Power	32,060	322
3	Medium Light and Power	49,239	2,515
4	Schedule E-19	22,810	8,513
5	Streetlights	869	0
6	Standby	434	0
7	Agriculture	9,029	92
8	Schedule E-20	25,599	15,306
9	Total Revenue ($1,000)	$254,897	$27,073
10	Total Benefit (MW)	2,034	216

F. Proposal for Streamlining Reporting Requirements

In the Scoping Memo, the Commission offered the IOUs an opportunity to present proposals for streamlining filings made to demonstrate compliance with their respective procurement plans. PG&E proposes that the Commission adopt proposals previously discussed and presented by the IOUs as described below.

1. Quarterly Procurement Transaction Compliance Report

D.04-12-048 directed the IOUs to file a joint proposal to reformat the quarterly procurement transaction compliance report to provide the Commission concise and coherent information. PG&E, Southern California Edison Company ("SCE"), and

San Diego Gas and Electric Company ("SDG&E") have worked collaboratively to draft a proposed streamlined quarterly procurement transaction compliance report and have discussed their proposal with Energy Division. However, the Energy Division has not taken any action on reformatting or streamlining this report. In order to make meaningful changes and improvements to this report, the Commission should direct the Energy Division to promptly review and approve or modify the IOUs' proposal on the format and contents of this report.

Recently, the Commission retained the services of an outside auditor to review the quarterly procurement transaction compliance reports for 2004, 2005 and 2006. The results of these audits may provide additional recommendations on how to streamline this quarterly report.

2. ERRA Activity Report

On December 2, 2005, SCE and PG&E filed a petition to modify D.02-12-074, and D.04-12-048 to change the requirement that energy utilities must file a periodic report on their ERRA with the Commission from a monthly report to a quarterly report. In discussions between SCE and the Commission's Utility Audit and Finance Compliance Branch ("UAFCB"), UAFCB indicated that the sheer volume of ERRA-related data submitted to the Energy Division each month causes major storage problems for the staff. A typical monthly ERRA report, including supporting documentation, consists of a few pages of summary information and approximately 1,000 pages of supporting documentation. Thus, the Commission's UAFCB is burdened with approximately 24,000 pages per year of monthly ERRA report documentation from SCE and PG&E. SCE and PG&E understand the burden placed upon the Commission's UAFCB staff to properly process and store the volume of confidential information provided by the utilities, since the utilities must prepare and duplicate the monthly submittals.

In their discussions on this matter, SCE and the UAFCB staff agreed that a more efficient way for the Commission to monitor the utilities' ERRA-related costs would be for SCE and the other utilities to submit quarterly summary reports with a monthly breakdown of costs to the UAFCB, and to make all supporting documentation available to the UAFCB upon its request. PG&E concurs with this proposal.

Thus, in their petition to modify, SCE and PG&E requested that the Commission modify D.02-12-074 and D.04-12-048 to allow the utilities to submit quarterly summary reports with a monthly breakdown of costs to the UAFCB, and to make all supporting documentation available to the Branch upon request, rather than submitting a 1,000-page ERRA report every month. PG&E recommends that the Commission expeditiously grant the petition to modify as a part of its effort to streamline reporting.

G. Ratemaking for the Emerging Renewable Resource Program

The purpose of this section is to describe PG&E's ratemaking proposal for the Emerging Renewable Resource Program ("ERRP"). As described in Volume 2, Section I.B.5, PG&E requests authorization to spend up to $30 million over two years for the ERRP. In subsequent LTPP filings, PG&E may request additional expenditure authorization should the pilot ERRP yield promising opportunities. Pending Commission authorization of the ERRP, which is not anticipated until a decision is issued in this LTPP, PG&E may seek separate Commission approval of specific projects to foster development of emerging renewable resources. PG&E would file an advice letter providing the project details, along with forecast expenditures. Upon Commission approval of that advice letter, PG&E would record the actual project costs by a debit to the ERRA. Upon approval of the ERRP in this proceeding, amounts for any pre-ERRP projects approved by the Commission would count towards the $30 million ERRP limit.

Once the ERRP is approved, PG&E would continue to file advice letters requesting approval of specific projects and related expenditures that PG&E proposes to support. Following Commission approval of the advice letter, the actual specific project ERRP expenditures would be recorded and recovered in the ERRA. To ensure that PG&E does not exceed the $30 million ERRP limit, PG&E will provide periodic detailed reporting of the approved projects and expenditures.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANTONIO J. ALVAREZ

Q 1 Please state your name and business address.

A 1 My name is Antonio J. Alvarez, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am manager of Long-Term Energy Policy and Planning in the Energy Procurement organization.

Q 3 Please summarize your educational and professional background.

A 3 My education includes a Bachelor of Science degree in Civil Engineering from the Universidad Javeriana, a Master of Science degree in Engineering Management from Stanford University, and a Master of Business Administration degree from the University of California in Berkeley. I joined PG&E in September 1977. Since that time, I have held various positions in planning and contract analysis and administration.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section I.B.4, "Expiration of California Department of Water Resources Contracts Impact" and Volume 2, Section IV.A, "The Commission Should Increase the Current Planning Reserve Margin of 15% to 17% Reserves for a 1-in-2 Peak Demand to 16% Reserves on a 1-in-10 Peak Demand."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAVID P. BAYLESS

Q 1 Please state your name and business address.

A 1 My name is David P. Bayless, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am a manager in the Energy Revenue Requirements Department. I am responsible for a variety of projects related to short-term electric procurement cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Arts degree in History from the University of California, Berkeley. I joined PG&E in August 1993 and held positions of increasing responsibility in the Gas Regulatory Policy and Analysis, Power Contracts, and Electric Supply Settlements Departments. In 1999, I joined Utility.com as director of Regulatory Affairs. In 2004, I returned to PG&E to assume my current responsibilities as manager of the generation procurement cost recovery and analysis section in Energy Revenue Requirements.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section IV.F, “Proposal for Streamlining Reporting Requirements.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KEVIN T. BUTLER

Q 1 Please state your name and business address.

A 1 My name is Kevin Butler, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I currently work in Energy Supply at PG&E where I hold the position of director of New Resource Procurement. I manage commercial arrangements to bring new generation on line, which involves the management of solicitation processes, contract negotiations and overseeing development activities.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration specializing in Financing and Marketing from the University of California at Berkeley.

Prior to my current position at PG&E, my experience includes over 16 years in the independent power and utility industries. At PG&E, I held the position of senior director of Corporate Development for PG&E Corporation and director of Finance at PG&E Enterprises where I was responsible for large energy and financing transaction processes, investments in generating facilities and energy infrastructure, and the divestiture of energy assets. I also held the positions of director of Finance and Development at FlowWind Corporation and assistant treasurer at CalEnergy where my responsibilities included financing power generation facilities and developing power plants.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section II.D, “Implementation of AB 1576.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CHRISTOPHER GROFF

Q 1 Please state your name and business address.

A 1 My name is Christopher Groff, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant, P.O. Box 56, Avila Beach, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am the manager of the nuclear fuels purchasing group at Diablo Canyon Power Plant (DCPP). I am responsible for the fuel fabrication contract and support the purchase of feed materials for each fuel reload.

Q 3 Please summarize your educational and professional background.

A 3 I have received a Master of Science degree in Nuclear Engineering from the Ohio State University and a Bachelor of Science degree in Mechanical Engineering from Purdue University. I have over 30 years of professional experience in the nuclear industry, including engineering design, emergency planning, surveillance testing, and fuel purchasing.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section IV.D, "Nuclear Fuel Plan."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GARRETT P. JEUNG

Q 1 Please state your name and business address.

A 1 My name is Garrett P. Jeung, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am a director in the Energy Procurement organization. I am responsible for energy procurement negotiations and execution of more complex transactions, covering various business needs such as conventional energy, renewable energy, financial hedging and resource adequacy.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering in 1980 an a Masters in Business Administration in 1985, both from the University of California, Berkeley. I rejoined PG&E in 2003 as the director of the Electric Procurement department. Since April 2006 I have been the director of the Structured Transactions department.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section IV.C.1, "Electricity and Gas Portfolio Hedging Plan."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF PETER E. KOSZALKA

Q 1 Please state your name and business address.

A 1 My name is Peter E. Koszalka, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am the manager of the electric fuels group in PG&E’s Energy Supply Department. I am responsible for physical and financial trading of gas in support of PG&E’s allocated DWR contracts, PG&E’s company-owned generating facilities, and PG&E’s tolling agreements.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science degree in Chemical Engineering from the University of California, Berkeley, in 1983. From 1983 to 1998, I was employed by PG&E in various positions including account representative, industrial power engineer, director of market relations (California Gas Transmission or CGT), and director of pricing and market research (CGT). In 1995, I earned a Master of Business Administration degree from California State University, Hayward. From 1998 to 2002, I was employed by various companies in a variety of positions related to the energy industry including product manager for direct access meter and data services, director of operations and independent consultant. I was re-hired by PG&E in 2003 to manage PG&E’s electric fuels function.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section III.A, “Gas Hedging Strategies for Electric Procurement Portfolios.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL KOWALEWSKI

Q 1 Please state your name and business address.

A 1 My name is Michael Kowalewski, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am a senior gas trader in the electric fuels group in PG&E's Energy Supply Department. I am responsible for planning, procuring and trading gas supply and gas assets in support of PG&E's allocated DWR contracts, PG&E's company-owned generating facilities, and PG&E's tolling agreements.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics from the University of California, Berkeley, in 1992. From 1992 to present, I have been employed by PG&E in various positions including senior energy trader at PG&E's Golden Gate Market Center, senior project manager, product manager for interstate pipeline capacity, rates analyst, gas pricing analyst and qualifying facilities resource analyst.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section IV.C.2, "Gas Supply Plan."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF HAROLD O. LA FLASH

Q 1 Please state your name and business address.

A 1 My name is Harold O. La Flash, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am the director of renewable energy policy and planning in PG&E's energy procurement organization.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science degree in Mechanical Engineering from the University of Wisconsin – Madison, and a Masters in Business Administration degree from Saint Mary's College, Moraga, California. I joined PG&E in January 1980 and have held various positions involving energy efficiency, nonutility generation, tariffs, and gas transportation. In 1997, I moved to PG&E Corporation where I held positions in corporate development and business planning. I returned to the utility in January 2004 as director of integrated resource planning and policy. I assumed my current position in March 2006.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section I.B.5., "Energy Action Plan Goal of 33% Renewables by 2020," and Volume 2, Section I.B.6., "Impact of New Clean Energy Loads on Procurement."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOE LAWLOR

Q 1 Please state your name and business address.

A 1 My name is Joe Lawlor, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am on rotation as the manager of the market design section of PG&E's Energy Procurement Department. My work has included representing PG&E's Energy Procurement Department for many of the issues in the Commission's Resource Adequacy proceeding.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelors of Science degree in Business Administration from San Francisco State University, my Masters degree in Business Administration from the University of San Francisco, and I am a Certified Public Accountant in the state of California. My experience has been largely focused in either accounting or energy at any time. I have worked in the equivalent of my current group, market design, for approximately four years.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section I.B.1, "Impact of RA on Costs and Procurement."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TODD STRAUSS

Q 1 Please state your name and business address.

A 1 My name is Todd Strauss, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I hold the position of senior director of Energy Policy, Planning, and Analysis. I support energy procurement activities by leading policy formulation, and providing guidance and oversight for long-term planning, valuation analysis and portfolio analysis.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Mathematics from the Massachusetts Institute of Technology. I hold a Ph.D. in Industrial Engineering and Operations Research from the University of California at Berkeley.

I have worked as an Assistant Professor at the Yale School of Management, a principal at the consulting firm PHB Hagler Bailly, and director of Quantitative Analysis at an affiliate company of Pacific Gas and Electric Company.

In 2003, I joined PG&E as director of Quantitative Analysis. I was appointed to my current position in 2006.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section III.B, "Application of TeVaR to Measure the Customer Risk Tolerance Threshold."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WILLIAM TOM

Q 1 Please state your name and business address.

A 1 My name is William Tom, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am manager of Short-Term Electric Supply. I am responsible for electric procurement activities from the Hour-Ahead Timeframe (as defined by the CAISO) through the next 24 months.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Engineering degree in Civil Engineering from the University of California, Berkeley, and a Masters degree in Business Administration in Finance from California State University, Hayward. I am a registered Civil Engineer in the state of California. I joined PG&E in October 1971. Since that time I have held various positions of increasing responsibility in power plant design, wholesale power contracts, electric resources planning, and electric procurement.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section I.B.3, "Impact of Market Redesign and Technology Upgrade (MRTU) on Procurement Practices," and a portion of Volume 2, Section II.A, "Competitive Procurement RFO."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL G. WHITE

Q 1 Please state your name and business address.

A 1 My name is Michael G. White, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am currently the director of Credit and Risk Reporting. I am responsible for managing wholesale credit risks for the utility's energy portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Business Administration degree from the University of Ohio in 1974. I held various auditing jobs primarily in the manufacturing sector from 1974 to 1982. I joined PG&E's Internal Auditing Department in 1982 as a staff auditor and was promoted to a manager position in the early 1990s. I became director, Risk Management in April 2002. In April 2005, I moved to my current position.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section II.B, "Credit and Collateral Policies."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RAY D. WILLIAMS

Q 1 Please state your name and business address.

A 1 My name is Ray D. Williams, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am director of the Long Term Energy Policy and Planning Department within the Energy Procurement Organization.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from Clark University in 1975 with a Bachelor of Arts degree in Geography and from Stanford University in 1981 with a Master of Science degree in Civil Engineering. From 1975 to 1979, I was employed by the Massachusetts Executive Office of Environmental Affairs.

I began work with Pacific Gas and Electric Company in 1981 in the electric resource planning area with responsibility for demand forecasting and for issues related to Qualifying Facilities. In 1988, I worked as a senior power systems engineer in electric operations, with responsibilities for ECAC/Reasonableness proceedings and electric operations planning. In 1991, I transferred to the Rates Department where I became manager of the cost of service section, supervising the development of gas and electric marginal and embedded cost studies for ratemaking and other purposes. In June 1995, I became director of the Revenue Requirements Department, where I was responsible for overseeing PG&E's involvement in cases at the California Public Utilities Commission (CPUC) and other matters that may affect or involve the authorized level of revenue for the company's electric and gas utility service. In this capacity, I was a witness in the Diablo Canyon Ratemaking Proceeding (A.96-03-054). From 1998 to 2000, I was on rotation on matters related to PG&E's hydroelectric assets. From 2000 to 2004, I was a director in California Gas Transmission overseeing regulatory activities and was a policy witness in CPUC gas transmission rate cases. In June of 2004, I transferred to my current position as a director supporting regulatory activities and policy development related to long-term electric planning and procurement.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor:

- Volume 2 – Section I.A, “Introduction”;
- Volume 2 – Section I.B.2, “Impact of Greenhouse Gas Emission Performance Standard on Procurement”;
- Volume 2 – Portions of Section II.A, “Competitive Procurement RFOs”;
- Volume 2 – Section II.C, “Independent Evaluator”; and
- Volume 2 – Section IV-B, “Uncertainties and the Need for New Generation Resource Development.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF VALERIE J. WINN

Q 1 Please state your name and business address.

A 1 My name is Valerie J. Winn, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am a manager in the Energy Revenue Requirements Department. I am involved in a variety of projects relating to generation procurement, direct access, and nuclear decommissioning.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Economics from the University of Maryland, College Park, in December 1984. I joined PG&E in March 1997 as an analyst in the Capital Accounting Department. Since that time I have gained increasing responsibilities as a senior analyst and supervisor in that department. I joined the Revenue Requirements Department as a team leader in November 2000 and became a manager in April 2002. Prior to my employment with PG&E, I worked at the World Bank in Washington, D.C., as a consultant reporting directly to the Managing Director and Chairman of the Bank’s Private Sector Development Group. I also have several years of experience as an economic analyst with Joel Popkin & Company, where I developed price indices for capital equipment purchases for several telecommunications companies.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony in this proceeding is to sponsor Volume 2, Section IV.E, “Ratemaking Proposal for D.06-07-029 Cost Allocation Mechanisms.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK W. ZIMMERMANN

Q 1 Please state your name and business address.

A 1 My name is Mark W. Zimmermann, and my business address is Pacific Gas and Electric Company (PG&E), 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company.

A 2 I am a team lead in the Generation Procurement, Policy, and Planning section of the Energy Revenue Requirements Department of PG&E. I am involved in a variety of projects relating to generation procurement.

Q 3 Please summarize your educational and professional background.

A 3 I received Bachelor of Arts degrees in Physics and Mathematics from Point Loma College, a Master of Science degree in Nuclear Engineering from the Massachusetts Institute of Technology, a Certificate in Marketing from the University of California at Berkeley and a Master of Business Administration degree with a concentration in Finance from Golden Gate University.

Prior to joining PG&E, I was a senior management consultant in the Washington, D.C. office of Booz, Allen, and Hamilton, Inc. Since joining PG&E, I have worked as a nuclear generation engineer, nuclear regulatory engineer, senior probabilistic risk assessment engineer, senior rates analyst, senior business planner, and capital accounting supervisor. I have testified before the California Public Utilities Commission and have been a witness in Federal Energy Regulatory Commission proceedings.

Q 4 What is the purpose of your testimony?

A 4 The purpose of my testimony is to sponsor Volume 2, Section IV.G, "Ratemaking for the Emerging Renewable Resource Program."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.